the freehold advantage

why freehold royalty trust?
here are 4 reasons

Freehold
ROYALTY TRUST

2003 annual report

1 own mineral title lands in perpetuity

true off-the-top royalty income

Our royalty lands continue to be a distinguishing feature. We are one of the largest owners of mineral title lands in western Canada and the only energy trust with this kind of asset base.

816,800

gross acres of mineral title and gross overriding royalties

distributable income by source

85%

distributable income from royalties

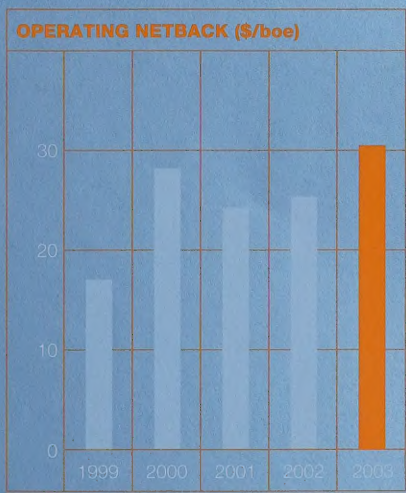
2 ▸ low cost structure = high netbacks

low costs

▸ A royalty interest offers the benefit of sharing in production, without exposure to the capital costs, operating costs and environmental costs associated with oil and gas production. Our high percentage of royalty income results in superior netbacks.

high netbacks

▸ **$30.51**
operating netback
($/boe)



3 solid, diversified asset base long-life reserves

diversified asset base

Freehold's properties are geographically widespread throughout western Canada. We have an interest in more than 15,000 royalty wells and 1,400 working interest wells and receive royalty income from more than 200 industry operators. This diversity lowers our risk.

16,000+

royalty and working interest wells

long-life reserves

11.0

year reserve life index

22.1

million boe reserves

4 ▸ low sustaining capital requirements

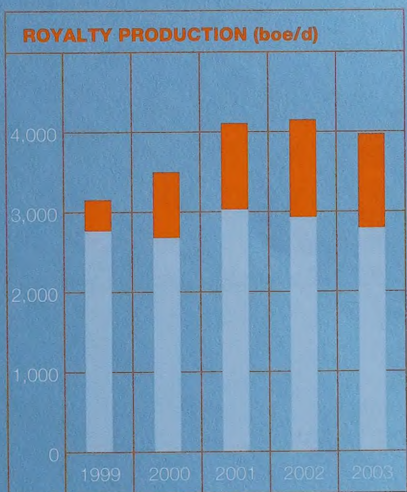
low capital expenditures

▸ Freehold does not incur capital expenditures on its royalty lands, only on its working interest properties. Therefore annual capital expenditures are modest and are funded directly from cash flow.

free drilling

30%

▸ ongoing development by lessees now accounts for about 30% of our royalty production



Free drilling
Base royalty production

3,234

▸ royalty wells drilled since inception adding reserves and production at no cost to Freehold

▸ trust profile

Freehold Royalty Trust has the royalty advantage. The Trust is one of the largest owners of privately-held mineral rights in western Canada. These royalty-generating properties provide income from the production and sale of crude oil, natural gas, natural gas liquids and potash. Royalty production is not subject to expenses such as operating and capital costs or environmental liabilities. Freehold also has working interests in 72 properties.

Freehold collects and regularly distributes income to Unitholders. Our objective is to provide investors with superior returns and consistent distributions. Growth in the underlying value of the Trust is achieved through ongoing development activity on the land base and the acquisition of new oil and gas assets.

HIGHLIGHTS

FINANCIAL

($000s, except unit data)	2003	2002	% Change
Gross revenue	73,166	63,143	+16
Distributable income	53,149	39,530	+34
Per Trust Unit ($)	1.70	1.31	+30
Capital expenditures	5,894	2,946	+100
Long-term debt	18,000	30,000	-40
Unitholders' equity	181,093	185,480	-2
Trust Units outstanding	31,454,236	30,225,236	+4
Weighted average	31,164,161	30,165,167	+3

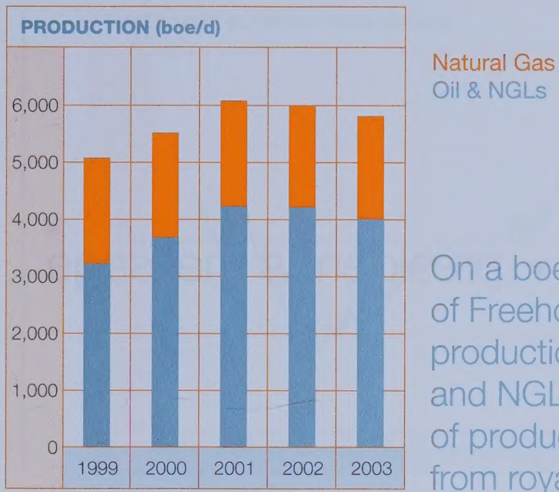
OPERATING

	2003	2002	% Change
Production			
Oil (bbls/d)	3,688	3,926	-6
NGLs (bbls/d)	317	288	+10
Natural gas (mmcf/d)	10.9	10.7	+2
Oil equivalent (boe/d)[1]	5,817	6,004	-3
Average sales price			
Oil ($/bbl)	32.77	31.25	+5
NGLs ($/bbl)	30.95	25.09	+23
Natural gas ($/mcf)	6.18	3.81	+62
Oil equivalent ($/boe)[1]	34.01	28.44	+20
Operating netback ($/boe)[1]	30.51	25.43	+20
Reserves (mboe)[1, 2]	22,052	25,410	-13
Undeveloped land (gross acres)	242,205	235,062	+3

1 To provide a single unit of production for analytical purposes, natural gas production and reserve volumes are mathematically converted to equivalent barrels of oil (boe) at a ratio of six thousand cubic feet of natural gas to one barrel of oil (6 mcf = 1 bbl). The boe ratio approximates an equivalent energy value, useful for comparative measures, but may not accurately reflect individual product values.

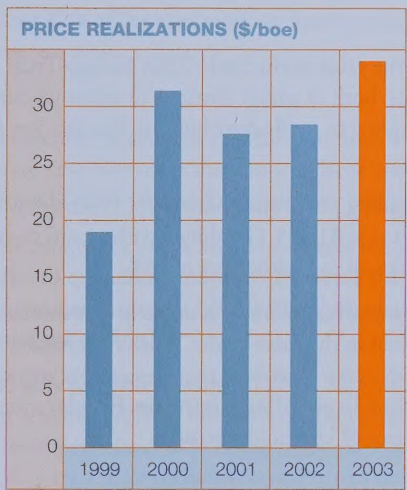
2 The 2003 reserves data is not directly comparable to historical data due to new reserve definitions and evaluation methodology that came into effect in 2003. Reserves for 2003 were evaluated under National Instrument 51-101 and are reported as net proved plus probable reserves. Previously, reserves were evaluated under National Policy 2-B and reported as gross proved plus half probable (established) reserves (see pages 32-36). The estimate of reserves for 2002 was 26,813 mboe on a gross established basis. The equivalent estimate on a net basis was 25,410 mboe as provided in this table.

5,817
production (boe/d)



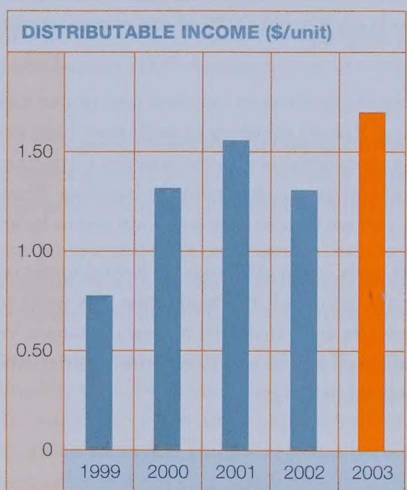
On a boe basis, 69% of Freehold's 2003 production was oil and NGLs and 68% of production came from royalty lands.

$34.01
average price realization ($/boe)

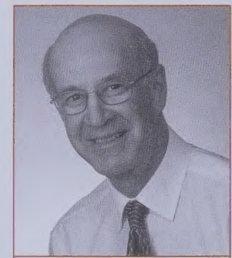


In 2003, Freehold's average selling price reached a record $34.01/boe. The Trust has not hedged any of its production.

$1.70
distributable income ($/unit)



Freehold paid a record $1.70 per Trust Unit in 2003, representing 88% of cash flow.


David J. Sandmeyer

president's message

In 2003, Freehold delivered the strongest performance in our history. Higher than expected commodity prices buoyed financial results and Unitholders directly benefited from record cash flows. Distributions for the year reached a record $1.70 per Trust Unit.

The last half of 2003 saw a notable rise in the value of the S&P/TSX Energy Trust Index. For the sector in general, the increase was driven primarily by two factors, both of which continue to influence current trading prices. First, crude oil and natural gas prices remained strong, contributing to stable distributions. Second, low interest rates resulted in high demand for income-yielding equity investments.

These factors contributed to record high trading prices and volumes for Freehold, particularly in the fourth quarter. The Trust Unit price climbed 50% to end the year at $16.35. Combined with record cash distributions, Freehold was a top performer in the sector, generating a total return to Unitholders of 66%.

We are pleased with this Trust Unit price performance but it is unlikely that similar future price appreciation can be expected without a significant event to add to the value of the Trust. As a royalty trust, we do not participate in high-risk exploration activities. Therefore, growth in our asset base requires a major acquisition. Regardless, with our royalty advantage, Freehold will continue to be a sound, rewarding investment. Regular monthly distributions should be considered the most important component of Unitholder returns.

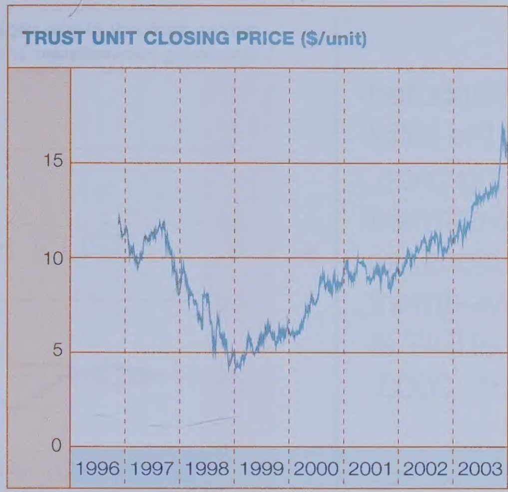
ROYALTY LANDS

Our royalty assets accounted for 85% of distributable income in 2003. Activity remains strong as our lessees continue to find new development opportunities. In 2003, operators drilled 576 wells on our royalty lands, close to a record for the Trust. Over the last seven years, our lessees have drilled more than 3,200 wells. This activity has helped to sustain our production and reserves – at no cost to Freehold. Roughly 30% of our current royalty production comes from incremental drilling on our original royalty assets.

We view continuing development on our royalty lands as an essential part of our future success. To date, we have seen no evidence to suggest that activity is waning. Record numbers of wells have been drilled in the past three years although average reserves and production per well has trended down as the western Canadian basin matures. The most active lessees in our royalty areas are among the largest oil and gas producers in the business. These companies have chosen certain of our royalty areas as key to their operations and we believe they will continue to be active in those areas.

With royalty interests in more than 15,000 wells, our audit program is vital to the ongoing health of the Trust. Continual monitoring ensures that royalties are correctly calculated and paid when new wells are drilled and that these royalties continue to be paid to the Trust if the properties are transferred to new operators. We are proud of the success of our efforts in this regard. During 2003, our audit staff issued audit exception queries amounting to $2.0 million. Since 1997, we have recovered $10.3 million through our audit program.

Closing the year at $16.35, the market value of Freehold Trust Units appreciated 50% from the end of 2002.



November 25, 1996
IPO Price $10.00

WORKING INTEREST PROPERTIES

Our 72 working interest properties accounted for 15% of distributable income in 2003. The two properties, Hayter and Pembina Cardium Unit No. 9, contributed 47% of the total working interest production. The primary focus of our $5.9 million capital program was in these two areas.

RESERVES

In 2003, the Canadian Securities Administrators issued new standards of disclosure for oil and gas activities (National Instrument 51-101). The rules incorporate new reserves evaluation standards and technology and require a different presentation for reserves disclosure. Freehold's 2003 year-end reserves have been evaluated in compliance with NI 51-101.

We also constituted a new three-member committee of the board to oversee the annual reserves evaluation. Previously, this responsibility was part of the mandate of our audit committee. However, the board decided to create a separate reserves committee in response to the recommendations of NI 51-101. Each member of this committee brings significant experience to the task of overseeing oil and gas disclosure.

Year-over-year, net reserves (total proved plus probable) declined 13% to 22.1 million boe, as reserves added through discoveries, acquisitions and development activities replaced only 53% of 2003 production. The application of NI 51-101 also resulted in downward revisions in estimates. About 60% of the revisions relate to a new 50-year cut-off, which assigns no value to producing reserves beyond 50 years. Other revisions were due to a more conservative approach in estimating and, to a lesser extent, to changes in reservoir performance. These changes also resulted in a decline in Freehold's reserve life index to 11.0 years from 11.9 years (see pages 32-36).

ACQUISITION STRATEGY

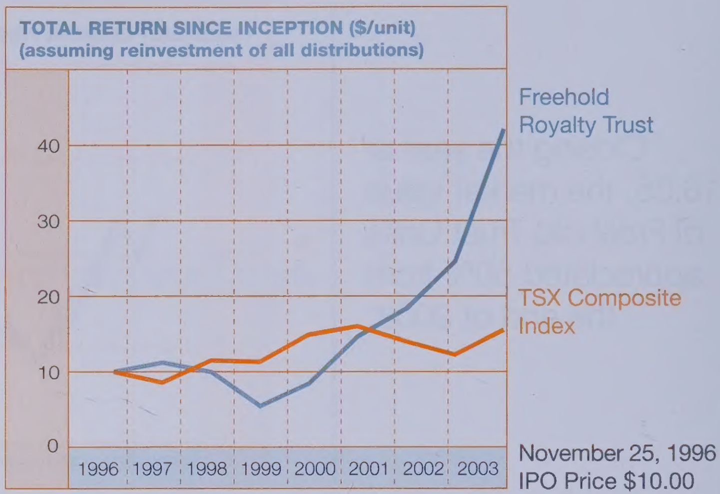
In 2003, we purchased a number of small interests for $3.4 million in aggregate. Combined, these properties will add approximately 100 boe/d to our production base in 2004. As anticipated, our average production declined 3% in the absence of a significant acquisition.

We continue to seek opportunities to add producing properties that complement our existing assets. Our bias is to acquire royalty interests, but we will also pursue working interests and/or corporate acquisitions if they meet our criteria. These include threshold requirements in terms of cash flow, return on investment, reserve life and future development potential.

Given the continued uncertainty in future commodity price expectations, having a conservative balance sheet is a distinct advantage. In 2003, we reduced long-term debt by $12.0 million, leaving $47.0 million of available capacity in our existing credit facility. This low level of debt gives us the flexibility to fund acquisitions from the unused capacity.

We see the potential to acquire assets jointly with Rife Resources Ltd. and Canpar Holdings Ltd. as another advantage. These two corporations are privately owned by the CN Pension Trust Fund and are managed by the same company that is responsible for Freehold's operations. The mandates of Rife and Canpar are different than the Trust, which gives us greater flexibility to look at a wider range of acquisition packages. This strategy has been successful in the past, with the Trust and Rife participating in the acquisition of properties in southeast Saskatchewan in 2001.

We have distributed almost 90% of the initial public offering price. Assuming reinvestment of all distributions, an initial $10 investment had a value of $42 at December 31, 2003.



GOVERNANCE

The management and directors of Freehold are genuinely committed to the principles of sound governance and business ethics. The board regularly examines its structure and activities to ensure they represent best practices and meet regulatory guidelines. In doing so, we recognize that good governance is more than a tick-the-box exercise – it's about being effective. Our primary focus has always been on representing the interests of our Unitholders. Our approach to governance is summarized on the following pages and is more fully described in our proxy circular.

In the last few years, disclosure and corporate governance practices have risen to a new prominence. New guidelines and regulations are evolving rapidly and we are working diligently to understand and implement the changes required. New rules mandating significant new continuous disclosure obligations (National Instrument 51-102) become effective March 30, 2004. The MD&A section of this annual report already incorporates the new disclosures that will be required. We are preparing to implement changes necessary to comply with new Investor Confidence Rules, which also come into effect on March 30, 2004. These rules address the roles and responsibilities of audit committees and CEO and CFO certification of annual and interim disclosures.

OUTLOOK

The monthly distribution rate remains set at $0.10 per Trust Unit. As in the past, a portion of income in excess of regular distributions may be directed toward repayment of long-term debt and/or working capital improvement. The remainder is distributed to Unitholders in the form of a quarterly top-up. With the anticipation of lower commodity price realizations in 2004, we forecast that cash flow and therefore distributable income will be lower than in 2003. Our current estimate is that cash distributions for 2004 will total $1.40 per Trust Unit. This guidance will be updated quarterly throughout the year. The major assumptions that form the basis for our distribution outlook, including sensitivities to changes in key variables, are discussed on page 31.

ACKNOWLEDGEMENTS

Our directors bring significant oil and gas, financial and business expertise to Freehold. I thank them for their insight and strategic guidance. Our senior management team is solid; each individual has over two decades of experience in managing the Trust's original assets. I would also like to acknowledge the skill and dedication of the Manager's employees, most of whom have been with us since before the Trust was formed. Their contributions will help to ensure the continued success of Freehold.

Together, we share an unwavering commitment to deliver value to you, our Unitholders. On behalf of our directors, management and employees, thank you for your continued support.

D J Sandmeyer

David J. Sandmeyer
President & Chief Executive Officer
March 16, 2004

governance of the trust

The governance structure of a trust is not the same as for a conventional corporation. The Trust holds a royalty granted by Freehold Resources Ltd. (the operating company), with certain rights under a Trust Indenture, a Unanimous Shareholder Agreement and a Management Agreement. The Trust has no directors. The board of directors of Freehold Resources Ltd. has a mandate to supervise the management of the business and affairs of the Trust in the best interests of the Unitholders. The board meets quarterly to review operating and financial results and when required to consider other matters.

RELATIONSHIP WITH CN PENSION TRUST FUND

Rife Resources Management Ltd, the Manager of the Trust, is a wholly-owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Fund. The CN Pension Trust Fund (the pension fund for employees of the Canadian National Railway System) holds 32% of the Trust Units. The Manager also manages two other entities on behalf of the CN Pension Trust Fund. These are Rife Resources Ltd., a private oil and gas company, and Canpar Holdings Ltd., a private royalty holding company. The board has addressed potential conflicts of interest of the Manager (which arise primarily out of acquisition activity) through an arrangement that provides for a sharing formula for any acquisitions completed by the Manager on behalf of the Trust.

BOARD INDEPENDENCE

Freehold has a seven-member board, the majority of whom are independent directors. Unitholders are entitled to elect five directors annually and two directors are elected by the Manager. The Chairman of the board is an independent director, as are the directors who chair the board's three standing committees.

BOARD MANDATE

Pursuant to the Management Agreement, the Manager has responsibility for the day-to-day operations of Freehold, subject to the board's general supervision and direction. Any amendment to the Management Agreement requires the approval of the board of directors. Significant operational decisions are made by the board, including:

- Issuance of additional Trust Units;
- Acquisition and disposition of properties for a purchase price or proceeds in excess of $5.0 million;
- Capital expenditures outside approved budgets;
- Establishment of credit facilities; and
- Payment of distributable income.

The board of directors is responsible in conjunction with the Manager for:

- Strategic planning;
- Identification of the principal business risks and implementing appropriate systems to manage these risks;
- Communication policy; and
- Integrity of internal controls and management information systems and monitoring senior management.

DISCLOSURE AND INSIDER TRADING POLICIES

Policies are in place to ensure that:

- Freehold has consistent standards and procedures for communication of both material and non-material information;
- Communication of material information to the investing public (whether positive or negative) is timely, factual and accurate, and is broadly disseminated in a non-selective manner in accordance with all applicable legal and regulatory guidelines; and
- The directors and officers of Freehold and the employees of the Manager have been given guidelines regarding trading in securities of the Trust, including mandatory blackout periods.

BOARD COMMITTEES AND THEIR MANDATES

The primary roles and responsibilities of the three standing committees of the board are summarized below. Each committee has written terms of reference and mandate approved by the board.

AUDIT COMMITTEE

Members: D. Nolan Blades (Chairman), Peter T. Harrison and Dr. P. Michael Maher, all of whom are independent directors.

- Reviewing and recommending to the board for approval the Trust's annual and interim financial statements;
- Reviewing and recommending to the board for approval offering documents, the annual information form, annual and interim MD&A and all public disclosure containing audited or unaudited financial information;
- Recommending to the board the appointment of external auditors;
- Evaluating and ensuring the independence of the Trust's auditors;
- Reviewing the Manager's internal control systems; and
- Reviewing risk management policies and procedures, including hedging, litigation and insurance.

GOVERNANCE & NOMINATING COMMITTEE

Members: Dr. P. Michael Maher (Chairman), D. Nolan Blades and William W. Siebens, all of whom are independent directors.

- Developing Freehold's governance policies and reviewing and approving annual corporate governance disclosure;
- Establishing a long-term plan for composition and size of the board including a process to identify, recruit and appoint new directors and recommending nominees for election to the board as well as reviewing the effectiveness of the board, its committees and its individual members;
- Reviewing and determining director compensation;
- Considering and recommending to the board option grants to outside directors of Freehold;
- Reviewing the general responsibilities and function of the board, its committees and the roles of the Chairman and the Chief Executive Officer;
- Assessing the needs of the board in terms of education, frequency, location and conduct of board and committee meetings; and
- Considering requests from individual directors or committees to engage outside advisors.

RESERVES COMMITTEE

Members: D. Nolan Blades (Chairman), Harry S. Campbell[1] and Peter T. Harrison, the majority of whom are independent directors.

- Recommending to the board the appointment of independent reserves evaluators;
- Reviewing the Manager's reporting on internal reserves standards and practices;
- Reviewing the Manager's procedures for providing information to the Evaluator; and
- Reviewing reserves and all public disclosure documents containing reserve information prior to board approval.

1 Mr. Campbell is a related director. He is Managing Partner of Burnet, Duckworth & Palmer LLP, which from time to time provides legal services to the Trust, Freehold Resources Ltd. and CN Pension Trust Fund and its affiliates.

William W. Siebens

Chairman of the Board,
Member, Governance &
Nominating Committee

D. Nolan Blades

Chair, Audit Committee,
Chair, Reserves Committee,
Member, Governance &
Nominating Committee

Harry S. Campbell Q.C.

Member, Reserves Committee

Tullio Cedraschi

Director

Peter T. Harrison

Member, Audit Committee,
Member, Reserves Committee

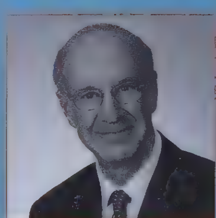
Dr. P. Michael Maher

Chair, Governance &
Nominating Committee,
Member, Audit Committee

Professional Engineer.

David J. Sandmeyer

President & CEO
Director



a Professional Engineer.

freehold's total land holdings

royalty lands

Royalty Areas	Land Holdings (gross acres)	Wells Drilled (gross)	Wells Drilled (net)	Average Daily Production: Oil & NGLs (bbls/d)	Average Daily Production: Natural Gas (mcf/d)	Average Daily Production: Oil Equivalent (boe/d)	Reserves (mboe)
Western Alberta	93,658	22	0.38	338	2,847	813	3,637
Bashaw/Leduc	66,300	39	0.70	150	1,078	329	1,052
Northeast Alberta	123,917	58	1.46	475	763	602	2,784
Saskatchewan Heavy Oil	62,764	49	2.66	714	411	782	2,184
Southeast Alberta	128,891	253	2.67	150	1,776	446	1,513
Hatton/Gull Lake	124,898	73	5.00	103	494	185	1,115
Southeast Saskatchewan	129,931	74	3.06	640	170	669	1,576
Other	86,414	8	0.08	54	550	146	865
Total	816,773	576	16.01	2,624	8,089	3,972	14,726

1 western alberta

Western Alberta represents a wide distribution of producing fields from the foothills at Turner Valley, Jumping Pound West and Wildcat Hills to the northern plains at Whitecourt. Production from this area is primarily natural gas and light oil.

Production increased 9% in 2003, aided by the drilling of a significant Viking gas well at Ricinus. Freehold's second largest royalty property at Caroline Swan Hills Unit #1, contributed 164 boe/d during 2003.

In 2003, the most active operators were Devon, ExxonMobil and ConocoPhillips.

2 bashaw/leduc

Bashaw/Leduc encompasses a wide diversity of productive zones from the Devonian Leduc Reef at a depth of 7,500 feet to the Upper Cretaceous Belly River and Edmonton zones at less than 2,500 feet.

Production declined 16% in 2003 as the drilling activity was unable to offset production declines.

In 2003 the most active operators were MEC, Centrica and ConocoPhillips.

3 northeast alberta

The main producing horizons in Northeast Alberta are the Viking and Mannville formations. The northern part of the area is characterized by the production of heavier oil and/or gas from the shallow (less than 3,300 feet) Mannville sands. Significant production units are the Wildmere Lloydminster "A" Unit No. 1, David Lloydminster C. Waterflood Unit #1, three Chauvin South units and five Wainwright units.

Production declined 7% in 2003. This area contains Freehold's third largest royalty property at Hayter which contributed 154 boe/d in 2003 (Freehold also owns a working interest at Hayter).

In 2003, the most active operators were EnCana, Rife, Southward and Zargon.

4 saskatchewan heavy oil

The major productive zones are the Mississippian Bakken, the Cretaceous Mannville and the Cretaceous Viking formations. Significant revenue properties are the Luseland and Hoosier Bakken pools, the Baldwinton and Tangleflags Sparky pools, and the Low Lake Waseca pool.

Production was down 26% from 2002 as a result of higher production decline rates at Baldwinton and Luseland and one time prior period positive adjustments in 2002.

In 2003, the most active operators were Baytex, Acclaim and Murphy.

5 southeast alberta

This area represents the largest number of gas wells for Freehold. Although shallow gas is the dominant play, oil production contributes significantly to revenue.

Production increased 34% in 2003. This was the most active area for drilling in 2003 with 253 wells drilled, including 189 unit wells.

In 2003, the most active operators were Petro-Canada, EnCana, EOG, Kenso and Canadian Natural.

6 hatton/gull lake

The Hatton/Gull Lake area of southwestern Saskatchewan provided revenue to Freehold from shallow gas production and from oil production from interests owned near Swift Current.

Production declined 18% in 2003. However, approximately 75% of the wells drilled in this area during 2003 had not commenced production by year end.

In 2003, the most active operators were EOG, Husky and Apache.

7 southeast saskatchewan

Southeast Saskatchewan, situated on the northern edge of the Williston basin, has the largest amount of undeveloped land. In the past decade, horizontal wells have become the favored method of exploitation and account for the majority of production.

2003 production increased 13% with the drilling of 74 wells.

In 2003, the most active operators were [illegible] Bison, Husky, Crescent Point and Upton.

▸ working interest properties

We hold direct working interests in 72 producing properties and receive revenue from approximately 1,200 producing wells. These properties accounted for 32% of the Trust's total production in 2003.

The majority (58%) of our working interest production comes from four properties. These are: Hayter, Pembina Cardium Unit No. 9 and Pouce Coupe South Boundary "B" Unit No. 2, all located in Alberta, and the Luseland property located in Saskatchewan. The 640-acre Hayter heavy oil property located in east central Alberta is the largest working interest property. Rife Resources Ltd. is the operator of the Hayter property. The Trust also owns a 48.5% title interest which generates a 6.25% royalty on the Hayter production.

2003 RESULTS

Working interest production remained steady in 2003, at 1,845 boe/d. Production declines in other areas were offset by drilling activity at the Hayter and PCU #9 properties. Capital expenditures were $5.9 million, the majority of which was spent at Hayter and PCU #9. We participated in the drilling of 74 (6.9 net) wells, all of which were successful.

2003 Highlights	Working Interest	Wells Drilled (gross)	Wells Drilled (net)	Capital Expenditures ($000s)	Average Daily Production Oil & NGLs (bbls/d)	Average Daily Production Natural Gas (mcf/d)	Average Daily Production Oil Equivalent (boe/d)	Reserves (mboe)
Hayter	23.5%	9	2.1	1,619	21	550	553	2,168
Pembina Cardium Unit No. 9[1]	9.9%	26	2.6	2,211	510	221	306	2,964
Luseland	20.0%	–	–	(33)	–	115	100	73
Pouce Coupe South Boundary "B" Unit No. 2	25.6%	–	–	156	81	86	115	511
Other (68 properties)	various	39	2.2	1,941	2,171	409	771	1,611
Total		**74**	**6.9**	**5,894**	**2,783**	**1,381**	**1,845**	**7,327**

1 Plus a 0.6% royalty.

2004 OUTLOOK

We will spend approximately $4.7 million on working interest properties in 2004. The majority of this capital will be used for drilling activity and facility expansion at Hayter where 10 (2.4 net) wells are planned, at PCU #9 where 25 (2.5 net) infill wells are planned and at Lashburn where two (1.3 net) wells are planned. We anticipate that development activity will add approximately 180 boe/d of production in 2004.

▸ management's discussion & analysis

The following discussion and analysis should be read in conjunction with the audited combined financial statements and notes contained in this Annual Report. It offers our assessment of Freehold's future plans and operations as at March 16, 2004, and contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. No assurance can be given that any of the events anticipated will transpire or occur, or if any of them do so, what benefits we will derive from them. We disclaim any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

The financial information contained herein has been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the years ended December 31, 2003 and 2002 and all dollar amounts are expressed in Canadian currency, unless otherwise noted. Additional information about Freehold, including our annual information form, is available on SEDAR at www.sedar.com.

CONVERSION OF NATURAL GAS TO OIL EQUIVALENT

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are mathematically converted to equivalent barrels of oil (boe). We use the international conversion of six thousand cubic feet of natural gas to one barrel of oil (6 mcf = 1 bbl). The 6:1 boe ratio approximates an equivalent energy value at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

SUPPLEMENTAL DISCLOSURE

We believe that distributable income, cash flow and netback are useful supplemental measures.

Distributable income provides investors with information on cash available for distribution. You are cautioned that distributable income should not be construed as an alternate to net income as determined by GAAP.

Cash flow, as used in this report, refers to funds generated from operations derived from our Combined Statements of Cash Flows. Cash flow represents cash provided by operating activities, before changes in non-cash working capital. We use cash flow to analyze operating performance, leverage and liquidity.

Operating netback, which is calculated as average unit sales price less royalties and operating expenses, and investor netback, which deducts administrative and interest expense and income and capital taxes, represent the cash margin for product sold, calculated on a per boe basis.

Distributable income, cash flow and netback do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculations of similar measure for other entities.

Our results are largely influenced by the price we receive for our oil and gas production.

OVERVIEW

Freehold is structured as a mutual fund trust under the *Income Tax Act* (Canada). This enables us to return the majority of our income to you in a tax-effective manner. We receive revenue from oil and gas properties as reserves are produced, which is paid to you on a regular basis over the economic life of the properties. Oil and gas are finite resources. Over time, reserves are depleted and capital investment is required to sustain production and cash flow.

We have a diverse production base, with interests in more than 16,000 wells throughout western Canada. This includes significant mineral title and gross overriding royalty interests that provide the majority of our revenue. Royalties offer the benefit of sharing in production, without exposure to the capital, operating and environmental costs associated with oil and gas production. This results in superior netbacks, which maximizes distributable income. Our 11-year reserve life, low sustaining capital investment requirements and the fact that so much development occurs on our lands at no cost to us make these assets very well suited to an energy trust.

RESULTS OF OPERATIONS

Our results are largely influenced by the price we receive for our oil and gas production. Commodity prices have demonstrated considerable strength in the last three years, resulting in increasing cash flow and earnings, despite lower production volumes. Higher prices have also enabled us to strengthen our balance sheet. Long-term debt has been reduced by 45% since the end of 2001.

Selected Annual Data ($000s, except per unit data)	2003	2002	2001
Revenue, net of royalty expense	69,969	60,434	58,403
Net income	37,026	27,557	27,299
Per Trust Unit, basic and diluted ($)	1.19	0.91	0.95
Total assets	210,140	224,322	235,585
Total long-term liabilities	18,000	30,000	33,000
Distributions per Trust Unit ($)	1.70	1.31	1.56

Since oil is priced in U.S. dollars, the negative effect of a stronger Canadian dollar in the latter half of 2003 is evident in our quarterly operating netbacks.

In the first quarter of 2003, the Manager exercised 1,000,000 Trust Unit options under a previously approved grant of options. The proceeds of this exercise ($9.2 million) were used to pay down bank debt.

Selected Quarterly Data	2003				2002			
($000s, except as noted)	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Revenue, net of royalty expense	20,804	17,070	16,865	15,230	12,331	15,586	15,806	16,711
Net income	12,933	9,340	8,863	5,890	4,520	7,703	8,016	7,318
Per Trust Unit, basic and diluted ($)	0.42	0.30	0.28	0.19	0.15	0.26	0.27	0.24
Distributions per Trust Unit ($)	0.40	0.50	0.40	0.40	0.24	0.32	0.37	0.38
Long-term debt	17,500	18,500	17,500	18,000	33,000	30,500	30,500	30,000
Production								
Oil and NGLs (bbls/d)	4,016	3,853	4,119	4,033	4,311	4,065	4,172	4,303
Natural gas (mmcf/d)	11.0	11.4	10.7	10.4	10.4	11.7	10.5	10.4
Oil equivalent (boe/d)	5,847	5,746	5,909	5,768	6,046	6,015	5,922	6,033
Average selling price								
Oil and NGLs ($/bbl)	39.70	31.10	31.17	28.66	25.24	32.39	34.03	31.74
Natural gas ($/mcf)	7.29	6.39	5.73	5.25	3.11	3.80	3.29	5.02
Oil equivalent ($/boe)	40.97	33.49	32.15	29.51	23.35	29.27	29.81	31.27
Operating netback ($/boe)	37.18	30.47	28.61	25.88	20.75	26.11	26.78	28.08
U.S./Canadian dollar exchange rate (Cdn. $)	0.6626	0.7158	0.7247	0.7600	0.6272	0.6435	0.6398	0.6372

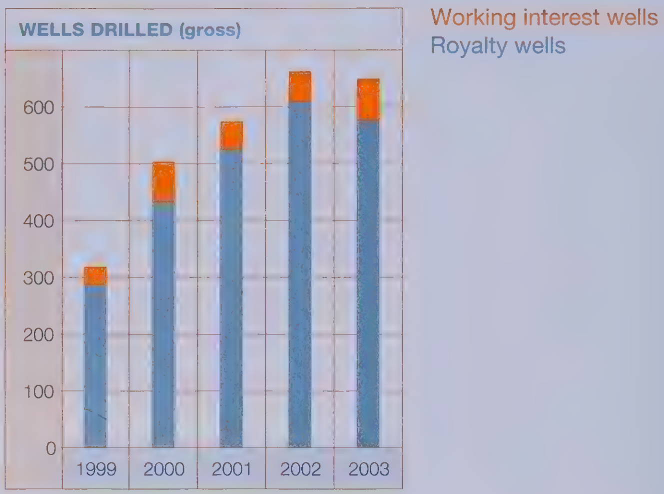
LAND OWNERSHIP

Our legacy assets stem from lands granted by King Charles II to the Hudson's Bay Company in 1670. Today, most of our land holdings are located south of the North Saskatchewan River, spanning the three prairie provinces. As at December 31, 2003 our total undeveloped land position was 242,205 gross acres.

Acreage Summary (gross acres)	2003	2002	2001
Alberta	642,092	632,047	636,958
Saskatchewan	340,475	341,134	339,197
British Columbia	25,946	25,946	25,946
Manitoba	2,224	2,224	2,444
Total	1,010,737	1,001,351	1,004,545

The majority of our assets are lessor royalties, based on mineral title ownership. Our "mineral title lands" cover about 482,000 acres and we have "gross overriding royalty" interests in approximately 325,000 acres. We have approximately 4,700 mineral agreements in place and receive royalty payments from over 200 industry operators on more than 15,000 royalty wells. The royalty rates vary from less than 1% (for some gross overriding royalties) to 20% (for lessor royalties). We also hold working interests in 193,964 gross (20,544 net) acres.

Drilling on Freehold's royalty lands generally mirrors industry activity, which is expected to remain strong in 2004.



DRILLING ACTIVITY

Drilling activity in western Canada was up 30% in 2003, with 21,694 wells drilled – a new record for the industry. A total of 650 (22.9 net) wells were drilled on our lands, up 29% from 2002 on a net basis. Industry drilling activity levels remain high and strong operating momentum is expected to continue through 2004.

ROYALTY LANDS

Development on our royalty lands remains robust. A total of 576 (16.0 net) wells were drilled with a 98% success rate. On a net-well basis, this was 25% higher than our 2002 results. At year-end, approximately 58% of these wells had not yet commenced production, most of which are shallow gas wells in Hatton/Gull Lake and Southeast Alberta. Three royalty areas: Southeast Saskatchewan, Western Alberta and Saskatchewan Heavy Oil, contributed the highest production additions from development and drilling activity in 2003.

Wells Drilled on Royalty Lands	2003		2002		2001	
(includes unitized wells)	(gross)	(net)	(gross)	(net)	(gross)	(net)
Oil	204	6.0	193	5.7	200	5.6
Natural gas	315	7.1	363	4.9	287	3.6
Service/other	46	2.3	42	1.7	21	0.7
Dry and abandoned	11	0.6	11	0.5	17	0.7
Total wells	576	16.0	609	12.8	525	10.6
Net success rate (%)		98		98		97

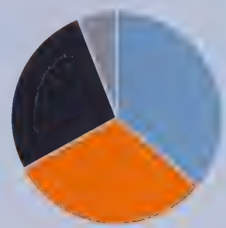
Drilling on the royalty lands should continue to provide new sources of income in future years as new wells reduce the rate at which production and royalty income would otherwise decline. Drilling on our royalty lands generally mirrors industry levels, which is expected to remain strong in 2004.

WORKING INTEREST PROPERTIES

We participated in the drilling of 74 (6.9 net) wells during 2003. The success rate was 100% and reflects the conservative nature of our capital investment program, which excludes participation in high-risk exploratory drilling. Hayter and Pembina Cardium Unit #9 were the most active areas in 2003.

Wells Drilled on Working Interest Properties	2003		2002		2001	
	(gross)	(net)	(gross)	(net)	(gross)	(net)
Oil	39	6.6	32	4.8	23	2.5
Natural gas	35	0.3	22	0.1	27	0.9
Service/other	–	–	–	–	–	–
Dry and abandoned	–	–	–	–	–	–
Total wells	74	6.9	54	4.9	50	3.4
Net success rate (%)		100		100		100

The Trust's production is oil weighted, with heavy oil accounting for 36% of total boe production in 2003.



PRODUCTION PROFILE (boe/d)
Heavy oil: 36%
Natural gas: 31%
Light and medium oil: 27%
NGLs: 6%

PRODUCTION

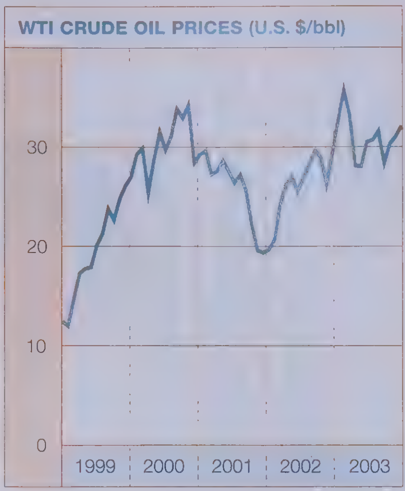
Our production base is geographically widespread throughout western Canada, with the majority of properties located in Alberta. Drilling on our royalty properties, combined with minor acquisitions, helps to offset the normal production decline. However, in the absence of a significant acquisition in 2003, production edged down 3%. On a boe basis, 69% of our production is derived from oil and natural gas liquids and more than half of this liquids production (36% of total boe production) is heavy oil.

Average Daily Production	2003	2002	2001
Oil and NGLs (bbls/d)	4,005	4,214	4,227
Natural gas (mmcf/d)	10.9	10.7	11.2
Oil equivalent (boe/d)	5,817	6,004	6,086

Average Daily Production by Product Type	2003	2002	2001
Royalty lands			
Oil (bbls/d)	2,396	2,657	2,512
NGLs (bbls/d)	228	211	278
Natural gas (mmcf/d)	8.1	7.7	7.9
Oil equivalent (boe/d)	3,972	4,153	4,109
Working interest properties			
Oil (bbls/d)	1,292	1,268	1,360
NGLs (bbls/d)	89	75	77
Natural gas (mmcf/d)	2.8	3.0	3.2
Oil equivalent (boe/d)	1,845	1,851	1,977
Potash (tonnes/d)	7.6	7.8	7.9

Production Reconciliation (boe/d)	Royalty Interest	Working Interest	Total Trust
2002 average daily production rate	4,153	1,851	6,004
Drilling on royalty lands	177	–	177
Development program	–	207	207
Acquisitions	36	–	36
Natural decline	(394)	(213)	(607)
2003 average daily production rate	3,972	1,845	5,817

In 2003, average WTI prices were 19% higher than in 2002 and 20% higher than in 2001.



MARKETING

ROYALTY LANDS

Our royalty lands consist of a large number of royalty properties and generally small volumes per property. A provision of the leases calls for our natural gas to be marketed with the lessees' production. We have chosen to market our oil production in the same manner.

WORKING INTEREST PROPERTIES

We market most of our working interest oil production using 30-day contracts to ensure the highest competitive pricing. We have elected to market the majority of our natural gas production with the operators' gas.

HEDGING

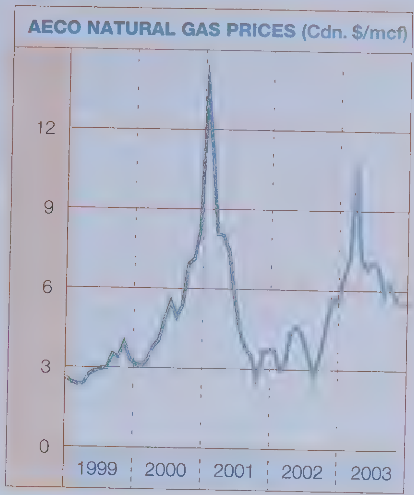
We believe that you have made your investment in Freehold for income and are willing to participate in the commodity price cycles. While hedging may be used to attempt to equalize distributions in a volatile pricing environment, it may also mask the market signals you should be watching for. In addition, there is a cost to hedging, including an opportunity cost in terms of distributable cash if the right hedging decisions are not made. Therefore, it has been our position to accept prices in the market and our production remains unhedged. This policy is subject to regular review by our board of directors.

PRICING

Benchmark commodity prices continued to demonstrate strength in 2003. WTI crude oil rose 19%. However, Bow River heavy oil edged up only 3%, reflecting wider price differentials for heavy oil. Year-over-year, the Canadian dollar rose 12%, an important factor, since oil is priced in U.S. dollars. The average AECO natural gas price was 65% higher in 2003.

Average Benchmark Prices	**2003**	2002	2001
WTI crude oil (U.S. $/bbl)	**31.04**	26.08	25.90
Bow River heavy oil (Cdn. $/bbl)	**32.68**	31.67	25.07
AECO natural gas (Cdn. $/mcf)	**6.70**	4.07	6.30
U.S./Canadian dollar exchange rate (Cdn. $)	**0.7158**	0.6369	0.6458

In 2003, average AECO natural gas prices were 65% higher than in 2002 and 6% higher than in 2001.



PRICE REALIZATIONS

In 2003, our average selling price reached a record $34.01 per boe. Natural gas realizations were exceptionally strong, averaging 62% higher than in 2002. Our oil realizations rose a more modest 5%, reflecting our product mix and the effects of a stronger Canadian dollar in the last half of 2003. The biggest factor was an increase in the light/heavy oil price differential, which averaged $10.46 per barrel in 2003, versus $8.27 per barrel the previous year. The price differential is significant to us, as approximately 36% of total boe production is heavy oil.

Freehold Average Selling Prices	2003	2002	2001
Oil ($/bbl)	32.77	31.25	24.42
NGLs ($/bbl)	30.95	25.09	29.91
Oil and NGLs ($/bbl)	32.63	30.83	24.88
Natural gas ($/mcf)	6.18	3.81	5.64
Oil equivalent ($/boe)	34.01	28.44	27.63
Potash ($/tonne)	[illegible]	143.33	153.98

REVENUE

We receive revenue from more than 200 industry operators. During 2003, 15 companies accounted for approximately 65% of our royalty income. These companies were (listed alphabetically): Apache Canada Ltd., APF Energy Inc., Bison Resources Ltd., BP Canada Energy, Canadian Natural Resources, ConocoPhillips Canada Energy Partnership, Devon Canada, EnCana Corporation, Enerplus Resources Corporation, Husky Oil Operations Limited, Murphy Oil Company Ltd., Nexen Petroleum Canada, Shell Canada Limited, Talisman Energy Canada and Upton Resources Inc.

The accompanying table demonstrates the net effect of price and volume variances on gross revenue. Gross revenue increased 16% to $73.2 million in 2003, despite moderately lower production volumes. Higher natural gas prices contributed 93% ($9.3 million) of the revenue increase in 2003.

Gross Revenue Variances ($000s)	2003 vs. 2002	2002 vs. 2001
Oil and NGLs		
Production increase (decrease)	(2,471)	(163)
Price increase	2,765	9,170
Net increase	294	9,007
Natural gas		
Production increase (decrease)	285	(568)
Price increase (decrease)	9,295	(7,487)
Net increase (decrease)	9,580	(8,055)
Other	149	306
Gross revenue increase	10,023	1,258

$10.3
million in audit recoveries

In the last seven years, our audit staff have issued audit queries amounting to $11.5 million and we have recovered $10.3 million to date.

EXPENSES

ROYALTIES PAID

Royalties are directly related to prices and the level of oil and gas sales. Oil and gas producers pay royalties to the owners of mineral rights from whom they hold leases. These are paid to the Crown (provincial and federal government) and freehold mineral title owners. In 2003, royalties paid on production relating to ownership in working interest properties totalled $3.2 million, or 4% of gross revenue. No royalties are paid to others on our share of production from the royalty lands. As the royalty owner, we receive the royalty as income from other companies.

Royalty Expenses ($000s, except per boe)	2003	2002	2001
Royalty expense[1]	3,197	2,709	3,482
Per boe ($)	1.51	1.24	1.57
As a percentage of gross revenue	4%	4%	6%

1 Net of Alberta Royalty Credit (ARC).

OPERATING EXPENSES

Operating expenses for working interest properties rose 11% in 2003. The increase stems largely from higher electricity and fuel costs in 2003. The industry is also experiencing rising costs as a result of increased competition for oilfield goods and services. We are somewhat sheltered from the effects of increased costs as the majority of our production comes from our royalty lands, which are not subject to these expenses. On a boe basis, operating costs of our total operations (including the royalty lands) rose 14% year over year, mainly due to lower production volumes in 2003.

Operating Expenses ($000s, except per boe)	2003	2002	2001
Working interest properties	5,190	4,679	4,415
Per boe ($)	7.71	6.93	6.12
Royalty interest properties	–	–	–
Per boe ($)	–	–	–
Total operating expenses	5,190	4,679	4,415
Per boe ($)	2.44	2.14	1.99
As a percentage of gross revenue	7%	7%	7%

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

We have a significant land administration, accounting and auditing requirement to administer and collect payments relating to more than 15,000 royalty wells. This includes systems to track lessee activity on the royalty lands. G&A expenses as a percentage of gross revenue have remained constant for the past three years.

G&A Expenses ($000s, except per boe)	2003	2002	2001
Gross G&A expenses	2,987	2,967	2,381
Less overhead recoveries[1]	(121)	(144)	(137)
Net G&A expenses	2,866	2,823	2,244
Per boe ($)	1.35	1.29	1.01
As a percentage of gross revenue	[illegible]	4%	4%

1 As we do not operate any of our royalty production, our overhead recoveries are minimal.

The Manager of the Trust is a wholly owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Fund (the pension fund for the employees of the Canadian National Railway Company). The Manager is reimbursed for overhead expenses incurred on behalf of the Trust. During the year, the Manager charged $2.3 million (2002 – $2.0 million) in G&A costs. At December 31, 2003, there was $343,000 (2002 – $148,000) included in accounts payable relating to these costs.

MANAGEMENT FEES

As part of the management agreement, the Manager receives a quarterly management fee paid in Trust Units. The Manager also earns an acquisition fee of 1.5% of the purchase price of oil and gas properties that we acquire. This fee is charged to capital assets as part of the properties acquired.

During 2003, the Manager received 90,000 Trust Units as the management fee, unchanged from 2002. The change in the ascribed value of management fees reflects the higher market price of the Trust Units compared with 2002. The Manager also received a fee of $52,000 relating to the property acquisitions completed during 2003. Since inception, the Manager has received total fees of $6.6 million, representing 2.7% of distributable income for the seven-year period.

The management agreement has a term of three years and is automatically renewed at the end of its term unless terminated one year prior to renewal. The management agreement will automatically renew on November 26, 2004.

Management Fees ($000s, except per boe)	2003	2002	2001
Management fees (paid in Trust Units)[1]	1,235	971	776
Acquisition fees (1.5%)	52	38	483
Total fees	1,287	1,009	1,259
Per boe ($)	0.61	0.46	0.57
As a percentage of gross revenue	2%	2%	2%
As a percentage of distributable income	2%	3%	3%

1 The ascribed value of the management fees is based on the closing Unit price at the end of each quarter.

INTEREST EXPENSE

Total interest expense declined 27% to $0.8 million during 2003, primarily due to lower prime borrowing rates and a 40% reduction in our long-term debt during the year.

Interest Expense ($000s, except per boe)	2003	2002	2001
Interest on operating line	2	16	17
Interest on long-term debt	776	1,044	1,797
Net interest expense	778	1,060	1,814
Per boe ($)	0.37	0.48	0.81
As a percentage of gross revenue	1%	2%	3%

NETBACKS

Netbacks, calculated on a boe basis, represent the cash margin on the sale of oil and gas. On our royalty production, we receive royalties from gross production revenue – before deduction of Crown royalties and operating costs. We do not incur capital expenditures, operating expenses, abandonment or site restoration expenses on royalty production. The following netback analysis demonstrates the positive effect of this royalty advantage.

2003 Netback Analysis ($ per boe)	Royalty Lands	Working Interest Properties	**Total Trust**
Gross revenue	34.42	34.54	**34.46**
Royalty expense (net of ARC)	–	(4.75)	**(1.51)**
Net revenue	34.42	29.79	**32.95**
Operating expense	–	(7.71)	**(2.44)**
Operating netback	34.42	22.08	**30.51**
General and administrative expense	(1.35)	(1.35)	**(1.35)**
Interest expense	(0.31)	(0.49)	**(0.37)**
Income and capital taxes	–	(0.66)	**(0.21)**
Funds generated from operations (cash flow)	32.76	19.58	**28.58**
Site reclamation fund contributions	–	(0.47)	**(0.15)**
Capital expenditures	–	(8.75)	**(2.78)**
Debt repayment from cash flow	(1.03)	–	**(0.71)**
Acquisitions	(2.34)	–	**(1.59)**
Working capital changes	1.67	1.67	**1.67**
Investor netback[1]	31.06	12.03	**25.02**

1 Excludes management fee paid in Trust Units.

Operating Netbacks ($/boe)	**2003**	2002	2001
Royalty lands	**34.42**	28.52	27.84
Working interest properties	**22.08**	18.53	16.95
Total Trust	**30.51**	25.43	24.30

DEPLETION AND CEILING TEST

Oil and gas properties and royalty interests, including the cost of production equipment and future capital costs associated with proved reserves, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties payable (see Application of Critical Accounting Policies and Estimates).

During 2003, the provision for depletion and depreciation was $21.7 million ($10.21 per boe), compared with $21.1 million ($9.62 per boe) in 2002. Reserves are independently evaluated on an annual basis. For the first three quarters of 2003, the estimate of proved reserves was based on the independent evaluation dated January 1, 2003, adjusted for acquisitions and production. The fourth quarter results were adjusted to reflect the annual reserve evaluation as at December 31, 2003 (see pages 32-36).

In accordance with our stated accounting policies, we apply a ceiling test to the carrying value of oil and gas assets, net of the provision for site restoration, plus future development costs, to ensure that such costs do not exceed future estimated net revenues from production of proved reserves at year-end prices and costs. Future net revenues are calculated after deducting future general and administrative costs, financing costs, site restoration costs and applicable income taxes. No ceiling test write-down has been required since inception.

RECLAMATION FUND

We are liable for ongoing environmental obligations and for the ultimate reclamation of our ownership share of the working interest properties upon abandonment. No similar responsibilities arise from the royalty lands. Ongoing environmental obligations are funded from cash flow. At December 31, 2003, our estimated share of future environmental and reclamation obligations for the working interest properties was approximately $7.0 million (2002 – $5.6 million).

A reclamation fund was established when the Trust was formed. The fund consists of cash invested in an interest-bearing account and is funded by quarterly cash payments. In 2003, contributions to the reclamation fund totalled $317,000, including interest. For 2004, quarterly contributions will increase to $100,000, plus interest, to ensure that future obligations can be met.

Reclamation Fund Summary ($000s)	Cumulative Since Inception	**2003**	2002	2001
Site restoration provision	1,773	**455**	346	352
Deposits to reclamation fund	1,691	**317**	240	240
Site restoration costs incurred	(402)	**(34)**	(118)	(101)
Reclamation fund balance	1,289	**1,289**	1,006	884

TAXES

Freehold is a taxable trust under the Canadian Income Tax Act. We distribute all of our taxable income to you as a Unitholder. By doing so, exposure to current tax at the Trust level is eliminated. In addition, we are exempt from future income taxes because we are contractually committed to distribute all of our income to Unitholders.

Capital taxes consist primarily of Large Corporations Tax, which is incurred on taxable capital employed in Canada, and the Saskatchewan Capital Tax, which is applied to both taxable capital and gross revenues in that province. Our subsidiary, Freehold Resources Ltd., is a Canadian corporation subject to tax in various jurisdictions. Freehold Resources Ltd. can deduct royalty payments to the Trust in determining its taxable income, and is generally liable for income taxes on its 1% residual interest. Freehold Resources Ltd. is subject to federal and capital tax in any jurisdiction (federal and provincial) in which it has a permanent establishment. In 2003, Freehold Resources Ltd. had taxable income that gave rise to current taxes of $340,000 (2002 – $122,000).

In the fourth quarter of 2003, we recorded a future income tax recovery of $291,000 related to the operations of Freehold Resources Ltd. due to enacted legislation that lowers corporate tax rates over the next five years. This resulted in a future income tax provision of $305,000 for the year ended December 31, 2003. The future income tax provision does not impact our current distributable income as it is a non-cash charge.

Taxes ($000s)	**2003**	2002	2001
Large Corporations Tax	**23**	48	52
Saskatchewan Capital Tax	**80**	95	49
Current income tax	**340**	122	–
Total	**443**	265	101

Tax Pools[1] ($000s)	**2003**	2002	2001
Canadian oil and gas property expense	**166,767**	171,205	188,346
Canadian development expense	**6,710**	4,913	4,888
Canadian exploration expense	**–**	–	68
Capital cost allowance	**5,763**	6,168	6,778
Unit issue expenses	**537**	806	1,075
Non-capital loss carryovers	**–**	–	443
Total	**179,777**	183,092	201,598

1 These amounts represent our direct tax pools as well as the tax pools for our subsidiary, Freehold Resources Ltd.

UNITHOLDER TAXATION

We are entitled to claim certain tax deductions available to all owners of oil and gas properties. By utilizing two principal deductions – the Canadian Oil and Gas Property Expense and the Resource Allowance deduction – cash distributions in the initial years were sheltered from income tax. Generally over time, an increasing percentage of the annual distributions will become taxable. The increase in the taxable portion is a result of a general reduction in tax pools available for future claims.

We paid $1.70 per Trust Unit as cash distributions during 2003. For Canadian tax purposes, 69% of these distributions ($1.1730 per Trust Unit) were taxable to you as a Unitholder as other income and 31% ($0.527 per Trust Unit) was a tax deferred return of capital. The tax deferred return of capital will reduce your adjusted cost base for purposes of determining a capital gain or loss upon disposition of the Trust Units. We estimate distributions in 2004 will be 70% taxable.

We are deemed to be a corporation for U.S. tax purposes. For U.S. taxpayers, distributions are 100% taxable, as dividends. If you are subject to U.S. tax you should consult your personal tax advisor.

DISTRIBUTABLE INCOME

The following analysis illustrates the royalty advantage. Mineral title and gross overriding royalty lands accounted for 68% of gross revenue and 85% of the Trust's distributable income in 2003.

2003 Distributable Income Analysis ($000s)	Royalty Lands	Working Interest Properties	Total Trust
Gross revenue	49,903	23,263	73,166
Royalty expense (net of ARC)	–	(3,197)	(3,197)
Net revenue	49,903	20,066	69,969
Operating expense	–	(5,190)	(5,190)
Net operating income	49,903	14,876	64,779
General and administrative expense	(1,957)	(909)	(2,866)
Interest expense	(451)	(327)	(778)
Income and capital taxes	–	(443)	(443)
Funds generated from operations (cash flow)	47,495	13,197	60,692
Site reclamation fund contributions	–	(317)	(317)
Capital expenditures	–	(5,894)	(5,894)
Debt repayment from cash flow	(1,499)	–	(1,499)
Property and royalty acquisitions	(3,386)	–	(3,386)
Working capital changes	2,426	1,127	3,553
Distributable income	45,036	8,113	53,149
Percentage contribution	85%	15%	100%

The following reconciliation shows the deductions from cash flow to arrive at distributable income. The change in working capital reflects lower accounts receivable at year-end 2003 versus 2002, due to higher commodity prices at the end of 2002. In 2003, Freehold distributed 88% of cash flow. Since inception in late 1996, we have paid out 84% of our total cash flow.

Payout Ratio ($000s)	2003	2002	2001
Funds generated from operations (cash flow)	60,692	51,607	49,829
Site reclamation fund contributions	(317)	(240)	(240)
Capital expenditures	(5,894)	(2,946)	(2,992)
Debt repayment from cash flow	(1,499)	(3,000)	(4,594)
Acquisitions	(3,386)	(2,326)	–
Working capital changes	3,553	(3,565)	3,261
Distributable income	53,149	39,530	45,264
Payout ratio	88%	77%	91%

1 Distributable income as a percentage of cash flow.

LIQUIDITY AND CAPITAL RESOURCES

We currently have no material contractual obligations requiring fixed or variable payments. We have a $50.0 million committed production facility on which $18.0 million was drawn at December 31, 2003. This facility is structured as a one-year committed revolving credit facility, extendible annually. In the event that the lender does not consent to an extension, the revolving credit facility will revert to a three-year, non-revolving amortizing term loan with equal quarterly principal repayments. In addition, we have available a $15.0 million demand operating facility and a US$10.0 million swap facility which were unused at year-end.

During 2003, we received $10.5 million on the exercise of Trust Unit options. These proceeds, combined with strong cash flow, enabled us to reduce our long-term debt by $12.0 million. At December 31, 2003, we had no short-term debt outstanding.

We have approximately $47.0 million of available capacity under our credit facilities, which is an important part of our acquisition strategy. A strong balance sheet provides us with considerable financial flexibility and liquidity to pursue potential acquisitions. We are actively seeking opportunities to further augment production and reserves through the purchase of producing properties, in particular royalty assets. While the goal is to maintain a high proportion of royalty income, working interest properties or corporate acquisitions may be considered, subject to our board's minimum investment thresholds.

Debt Analysis ($000s)	2003	2002	2001
Long-term debt	18,000	30,000	33,000
Short-term debt (operating line)	–	–	–
Less: working capital	4,367	7,920	4,316
Net debt obligations	13,633	22,080	28,684

Our net debt to cash flow ratio remains among the lowest in the energy trust sector. At 0.2:1, this ratio demonstrates our strong financial health. The reduction in net debt during 2003 had a positive effect on our leverage metrics.

Financial Leverage and Coverage Ratios	2003	2002	2001
Ratio of net debt to trailing cash flow	0.2:1	0.4:1	0.6:1
Distributable income to interest expense (times)	68.0	37.0	25.0
Net debt to distributable income (times)	0.3	0.6	0.6
Net debt to net debt plus equity (%)	7.0	10.6	12.7

ACQUISITIONS AND CAPITAL EXPENDITURES

We acquired three royalty properties and completed one property swap for $3.4 million (net of adjustments) in 2003. These properties will contribute approximately 100 boe per day to our royalty production base in 2004.

Acquisition Summary ($000s)	2003	2002	2001
Purchase price	3,512	2,532	32,168
Acquisition fee (1.5%)	53	38	483
Interest expense	12	–	623
Evaluation and legal costs	–	48	145
Purchase price adjustments[1]	(191)	(292)	(3,712)
Net acquisition cost	3,386	2,326	29,707

1 Net revenue from effective date to closing.

Our capital expenditure obligations are paid from cash flow, prior to the determination of distributable income. The amount of capital expenditures to be deducted is limited to 15% of annual net cash flow from operations. As we do not incur capital expenditures on our royalty lands, our operating capital requirements are relatively modest. In 2003, capital expenditures of $5.9 million amounted to 10% of cash flow.

Capital Expenditures ($000s)	2003	2002	2001
Development drilling	4,605	1,824	2,289
Plant and facilities	1,289	1,122	703
Total capital expenditures	5,894	2,946	2,992

For 2004, we have set a capital budget of $4.7 million. The majority of this capital will be invested in development projects at Hayter and Pembina Cardium Unit No. 9 in Alberta, and at Lashburn, Saskatchewan.

SOURCES AND USES OF FUNDS

The following table outlines our sources and uses of funds during the past three years.

Sources and Uses of Funds ($000s)	2003	2002	2001
Sources of funds			
Funds generated from operations (cash flow)	60,692	51,607	49,829
Equity issued, net of costs	10,501	40	30,602
Change in non-cash working capital	3,169	(3,555)	2,412
	74,362	48,092	82,843
Uses of funds			
Debt reduction	12,000	3,000	5,000
Site reclamation fund	317	240	240
Capital expenditures	5,894	2,946	2,992
Property acquisitions, net of costs	3,386	2,326	29,707
Distributions paid to Unitholders	53,024	39,524	44,924
Change in cash	(259)	56	(20)
	74,362	48,092	82,843

OUTSTANDING SHARE CAPITAL

As at March 16, 2004, there were 31,454,236 Trust Units outstanding.

NEW DISCLOSURE RULES

STANDARDS OF DISCLOSURE FOR OIL AND GAS ACTIVITY

On September 30, 2003, new standards for reserves disclosure came into effect, under National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities*. The Instrument prescribes new standards for the preparation and disclosure of oil and gas reserves and related estimates for Canadian companies. Additional information relating to our reserves is provided on pages 32-36 of this report.

CONTINUOUS DISCLOSURE OBLIGATIONS

Effective March 30, 2004, all reporting issuers in Canada will be subject to new disclosure requirements under National Instrument 51-102, *Continuous Disclosure Obligations*. We continue to assess the implications of this new Instrument, which will be implemented in 2004.

INVESTOR CONFIDENCE RULES

Effective March 30, 2004, most reporting issuers in Canada will be subject to new investor confidence rules under National Instrument 52-107, *Acceptable Accounting Principles, Auditing Standards and Reporting Currency*; National Instrument 52-108, *Auditor Oversight*; Multilateral Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*; and Multilateral Instrument 52-110 *Audit Committees*. We continue to assess the implications of these new Instruments, which will be implemented in 2004.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our financial statements are prepared within a framework of generally accepted accounting principles selected by management and approved by our board of directors.

The assets, liabilities, revenues and expenses reported in our financial statements depend to varying degrees on estimates made by management. These estimates are based on historical experience and reflect certain assumptions about the future that we believe to be both reasonable and conservative. We continually evaluate the estimates and assumptions.

An estimate is considered a critical accounting estimate if it requires management to make assumptions about matters that are highly uncertain; and if different estimates that could have been used would have a material impact.

The calculation of depletion is considered a critical accounting estimate. We follow the full cost method of accounting for property, plant and equipment. Oil and gas properties and royalty interests, including the costs of production equipment and future capital costs associated with proved reserves, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. An increase in estimated proved oil and gas reserves would result in a corresponding reduction in depletion expense.

The reserve and recovery information provided are only estimates. The actual production and ultimate reserves may be greater than or less than the estimates and the differences may be material. The process of estimating reserves is complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available, and as economic conditions change. The current estimates of oil and gas reserves and our future capital expenditures are based on an independent evaluation conducted as of December 31, 2003. Reserve estimates are updated annually at year-end and whenever a significant acquisition is completed.

NEW ACCOUNTING STANDARDS

HEDGING RELATIONSHIPS

The Canadian Institute of Chartered Accountants (CICA) issued Accounting Guideline 13, *Hedging Relationships* (AcG-13), which is effective for fiscal years beginning on or after July 1, 2003. AcG-13 establishes certain conditions for when hedge accounting may be applied. We have adopted this guideline, which has no immediate impact as we did not have any financial instruments in place during 2003.

DISCLOSURE OF GUARANTEES

Effective March 1, 2003, the CICA issued Accounting Guideline 14, *Disclosure of Guarantees* (AcG-14). AcG-14 requires that all guarantees be disclosed in the notes to the financial statements along with a description of the nature and term of the guarantee and an estimate of the fair value of the guarantee. We adopted this guideline on March 1, 2003. As we have no outstanding guarantees, there is no impact on current year reporting.

ASSET RETIREMENT OBLIGATIONS

The CICA approved Section 3110, *Asset Retirement Obligations* (ARO), effective January 1, 2004. This new standard requires that the fair value of obligations to de-commission facilities and other associated clean-up costs be recorded as an asset retirement obligation in the period in which it is incurred. We will adopt the new standard on January 1, 2004, and the asset retirement obligation will be reflected in the financial statements for the period ended March 31, 2004. When initially recorded, the fair value of the estimated ARO is recorded as a liability, with a corresponding increase in the related property, plant and equipment. In addition, the liability amount is increased each reporting period due to the passage of time and the amount of accretion is expensed in the period. Actual costs incurred upon the settlement of the ARO are charged against the ARO.

FULL COST ACCOUNTING GUIDELINE

The CICA issued Accounting Guideline 16, *Oil and Gas Accounting - Full Cost* (AcG-16) to replace CICA Accounting Guideline 5, effective January 1, 2004. The new guideline modifies the ceiling test calculation for future cash flows on an undiscounted basis using future prices for proved reserves. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. The cash flows are estimated using expected future product prices and costs are discounted using a risk free interest rate. We will adopt this guideline on January 1, 2004, and the new ceiling test calculation will be done for the first time at the end of the first quarter. The impact cannot be determined until the calculation is performed.

STOCK BASED COMPENSATION AND OTHER STOCK BASED PAYMENTS

Effective January 1, 2004, the CICA amended Section 3870, *Stock Based Compensation and Other Stock Based Payments*. The amendment requires that all stock based payments be measured using the fair value method of accounting and recognize the compensation expense on the financial statements. Freehold will adopt the new standard on January 1, 2004. There is no immediate effect on our financial results, since we currently have no options outstanding.

BUSINESS RISKS

The distributable income of an energy trust is subject to virtually the same industry risks and conditions faced by conventional oil and gas companies. The most significant of these include, but are not limited to, the following:

- Fluctuations in commodity prices and quality differentials as a result of weather patterns, world and North American market forces or shifts in the balance between supply and demand for crude oil and natural gas;
- Our reserves will deplete over time through continued production and we and our lessees may not be able to replace these reserves on an economic basis;
- Stock market volatility and the ability to access sufficient capital from internal and external sources;
- Variations in currency exchange rates;
- Industry activity levels and intense competition for land, goods and services and qualified personnel;
- Operational or marketing risks resulting in delivery interruptions, delays or unanticipated production declines;
- Imprecision of reserve estimates and uncertainty of depletion and recoverability of reserves;
- Changes in government regulations and taxation; and
- Safety and environmental risks.

As a royalty trust, we are also subject to the following risks:

- As 40 royalty payors account for approximately 90% of our royalty income, changes to their businesses may have a significant effect on our results;
- Potential Unitholder liability; and
- Higher prime borrowing rates, which may increase interest expense on our debt, and which may make fixed income investments more attractive to investors of Trust Units.

MITIGATING STRATEGIES

We employ the following strategies to mitigate these risks:

- We have interests in more than 16,000 oil and gas wells across western Canada. This diversified revenue stream limits the size of any one property with respect to our total assets;
- We are not liable for abandonment and site reclamation costs on our royalty lands;
- We maintain an aggressive auditing program to ensure that royalties are paid on our production from our lands, that our royalties paid are in accordance with the prices obtained by the royalty payor and that unwarranted or excessive deductions are not being taken. During 2003, our audit staff issued audit exception queries amounting to $2.0 million, bringing the total amount of audit exception queries since 1997 to $11.5 million, $10.3 million of which has been recovered.
- We adhere to strict investment criteria for acquisitions, seeking royalty and working interest properties that have high netbacks, long reserve life, low risk development potential and product diversification;
- Due to our high percentage of royalty lands, we have the lowest all-in cost structure of our peer group. In addition, we maintain focus on controlling direct costs to maximize profitability;
- We market our products to a diverse range of buyers. Currently, we do not have any commodity price, exchange rate or interest rate hedging programs in place and do not anticipate a change in that policy;
- We employ a qualified team of oil and gas professionals with many years of experience and knowledge in managing our assets;
- The possibility of any personal liability of Unitholders is very remote. Our operations are conducted in such a way as to avoid risk of liability on the Unitholders for claims against us. All contracts contain provisions that exclude any liability of Unitholders and we provide an indemnification to Unitholders;
- We maintain levels of liability insurance that meet or exceed industry standards; and
- We employ a conservative approach to debt management. As circumstances warrant, we allocate a portion of cash flow to debt repayment.

OUTLOOK

We are entering the fifth year of what might be called a bull market for crude oil. With WTI oil prices averaging US$31.04 per barrel and AECO natural gas prices averaging $6.70 per mcf in 2003, commodity prices remain at the high end of the historical range. The higher Canadian currency has had a dampening effect on our results because oil is priced in U.S. dollars. However, higher WTI prices during 2003 have helped to offset the impact on Canadian dollar realizations. We continue to believe that oil prices will trend downward as reconstruction in Iraq progresses and its export volumes increase. However, at the time of writing, inventories remain tight and oil prices continue to reflect uncertainty of the timing of increased supply from Iraq as well as increased demand from developing countries such as China.

North American demand for natural gas remains firm. Prices also remain strong due to the recent cold weather in the eastern United States and uncertainty about the industry's ability to replace withdrawals from storage. Changes in seasonal weather patterns will undoubtedly continue to cause short-term price fluctuations. But overall, we believe natural gas prices will have less downside risk.

DISTRIBUTION OUTLOOK

With the anticipation of lower commodity price realizations in 2004, we forecast that cash flow and therefore distributable income will be lower than in 2003. Our current estimate is that cash distributions for 2004 will total $1.40 per Trust Unit, based on the following assumptions. This guidance will be updated quarterly throughout the year.

2004 Distribution Outlook	February 19, 2004
Estimated cash distributions ($/Trust Unit)	1.40
Assumptions	
Average daily production, excluding acquisitions (boe/d)	5.755
Average WTI oil price (U.S. $/bbl)	30.00
Average AECO natural gas price (Cdn. $/mcf)	5.25
Average light/heavy oil price differential (Cdn. $/bbl)	10.00
Average Canadian/U.S. dollar exchange rate (Cdn. $)	0.76

Oil and gas price fluctuations, interest rate changes, currency exchange rates, levels of production and light/heavy oil price differentials can all influence our distributable income. Our production is 63% weighted to oil and we are particularly vulnerable to swings in the light/heavy oil price differential, as approximately 57% of our oil production is heavy oil. It is also inherently difficult to predict activity levels on our royalty lands, since we do not know the future plans of the various operators.

SENSITIVITIES

The following table provides an analysis of the potential impact these key factors may have on distributable income in 2004.

Sensitivity Analysis[1]		Estimated Change in Distributable Income	
Variables	Change (+/–)	($000s)	($/Trust Unit)
WTI crude oil price	U.S. $1.00/bbl	945	0.03
Light/heavy oil price differential	Cdn. $1.00/bbl	630	0.02
Natural gas price	Cdn. $0.25/mcf	630	0.02
Cdn./U.S. dollar exchange rate	$0.01	630	0.02
Interest rates	1%	315	0.01
Oil and NGLs production	100 bbls/d	630	0.02
Natural gas production	1,000 mcf/d	945	0.03

1 Based on 2004 budget forecast.

report on reserves

This annual report contains a summary of the reserves data and other information that has been prepared and filed with securities regulatory authorities in accordance with National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities (NI 51-101).

Management is responsible for the preparation and disclosure of information with respect to the reserves of the Trust. Trimble Engineering Associates Ltd. (Trimble), an independent qualified reserves evaluator, has evaluated the Trust's reserves data and prepared a report. The reserves committee has met with management and Trimble to review the reserves data, including the reserves estimates methodology, available tax pools and future price/cost assumptions utilized in the analysis, and the reconciliation of changes in reserves and future net revenue.

The board of directors has, on the recommendation of the reserves committee, approved the content of the reserves data. The complete report, as required by NI 51-101, is available on SEDAR (www.sedar.com).

David J. Sandmeyer, P. Eng.
President & Chief Executive Officer

D. Nolan Blades, P. Eng.
Chair, Reserves Committee

engineer's report

TO THE UNITHOLDERS OF FREEHOLD ROYALTY TRUST

This letter is to confirm that Trimble Engineering Associates Ltd. (Trimble) was retained as an independent qualified reserves consultant to evaluate the petroleum and natural gas reserves of Freehold Royalty Trust. The reserves data are the responsibility of the Trust's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the new industry-developed Canadian Oil and Gas Evaluation (COGE) Handbook. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We have no responsibility to update our report for events and circumstances occurring after its preparation date. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Trimble Engineering Associates Ltd.
February 19, 2004

Our 2003 reserves data is not directly comparable to historical data, due to new reserve definitions and evaluation methodology.

SUMMARY OF RESERVES

On September 30, 2003, new standards of disclosure for oil and gas activities came into effect, under NI 51-101. The Instrument prescribes new standards for the preparation and disclosure of oil and gas reserves and related estimates for Canadian companies.

Summary of Net Interest Reserves	Proved Developed Producing	Proved Developed Non-producing	Proved Undeveloped	Total Proved	Proved Plus Probable
Light and medium oil (mbbls)	4,717	–	12	4,729	6,233
Heavy oil (mbbls)	4,848	–	266	5,114	8,106
Natural gas (mmcf)	27,275	216	8	27,499	38,449
NGLs (mbbls)	1,009	1	1	1,011	1,304
Total (mboe)	15,120	37	280	15,437	22,052
Reserve life index (years)	8.3	–	–	8.3	11.0
Potash[1] (mtonnes)	60,352	–	–	60,352	60,352

1 Potash reserves, evaluated by Rife Resources Ltd., are not subject to NI 51-101.

The 2003 reserves data is not directly comparable to historical data, due to the new reserve definitions and evaluation methodology under NI 51-101. Previously, reserves were evaluated in accordance with National Policy 2-B. The key differences with respect to the presentation of our 2003 reserve data are summarized below.

- **Confidence Thresholds in Reserves Definitions** – Under NI 51-101, "proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. "Proved plus probable" reserves are those reserves expected to be recovered. At the corporate reporting level, there must be a 90% probability that at least the estimated proved reserves will be produced. For "proved plus probable" reserves, there must be a 50% probability that at least the estimated reserves will be recovered.

- **Reporting "Proved Plus Probable", not "Established" Reserves** – Probable reserves will no longer be risked by 50% as they are implicitly risked in the estimate. Although the reserve definitions are different, the new proved plus probable reserves are assumed to be similar to the proved plus half probable (i.e. established) reserves reported previously under National Policy 2-B reserves definitions. In this report, reserves are presented as proved plus probable, unless otherwise noted.

- **Reporting Net Interest Reserves** – In this report, our reserves are reported on a net interest basis (our share of working interest properties, minus royalties payable; plus royalties receivable). We are somewhat unique in that the majority of our assets are royalty interests. The new definition of gross reserves excludes royalty interests. This results in the anomaly of our gross reserves being lower than net reserves.

- **Truncation of Producing Reserve Life** – A recommended practice under NI 51-101, is that the producing reserve life will be truncated 50 years out. Reserves with extremely long reserve life are affected, however subject to annual review a portion of these reserves may be added back each year. This 50-year cut-off recognizes that the present value of these reserves to be produced in the future is both small and uncertain.

- **Reserve Life Index** – Under NI 51-101, it is recommended that the reserve life index (RLI) be calculated by dividing the evaluators' forecast of 2004 net interest production into the remaining net interest proved plus probable reserves. Previously, we calculated RLI based on actual gross production for the year and gross established reserves. The 50-year truncation also has the effect of reducing RLI.

As at December 31, 2003, reserves were assigned to approximately 13,950 wells. Before revisions in estimates, reserves added through discoveries, acquisitions and development activities replaced 53% of 2003 production. Year-over-year, net interest reserves (proved plus probable) declined 13% to 22.1 million boe. The average cost of reserve additions was $11.35 per boe.

The present value of our future net revenue, discounted at 10%, is $261.4 million, including $5.6 million for potash, evaluated by the Manager. This represents a 7% decline over 2002, which is primarily related to reduced reserve volumes. Future net revenue estimates are based on the January 2004 escalated oil and gas price and exchange rate forecasts by an independent qualified reserves evaluator.

Net Present Value[1] ($000s)	Discounted at 0%	5%	**10%**	15%
Proved				
Developed producing	406,803	264,713	**202,359**	167,133
Developed non-producing	1,227	1,009	**856**	745
Undeveloped	3,276	2,481	**1,958**	1,590
Total proved	411,306	268,203	**205,173**	169,468
Probable	169,324	81,909	**50,618**	35,531
Total proved plus probable	580,630	350,112	**255,791**	204,999
Potash[2]	19,706	8,951	**5,551**	4,068

1 Forecast prices and costs, before tax, including ARC. Based on the January 2004 escalated oil and gas price forecasts by an independent qualified reserves evaluator.
2 Potash price forecast prepared by Rife Resources Ltd.

Net Present Value By Product Type[1] ($000s)	Proved Reserves	**Proved Plus Probable Reserves**
Light and medium oil	73,492	**88,737**
Heavy oil	61,196	**79,819**
Natural gas	70,484	**87,235**
Potash[2]	5,551	**5,551**

1 Forecast prices and costs, before tax,including ARC, discounted at 10%. Based on the January 2004 escalated oil and gas price forecasts by an independent qualified reserves evaluator.
2 Potash price forecast prepared by Rife Resources Ltd.

Reconciliation of Net Interest Reserves	Proved (mboe)	Probable (mboe)	**Proved Plus Probable** (mboe)	**Net Present Value**[1] ($000s)
December 31, 2002	21,109	4,301	**25,410**	**275,021**
Extensions and improved recovery	26	14	**40**	**476**
Technical revisions	(4,181)	1,802	**(2,379)**	**(12,136)**
Discoveries	460	411	**871**	**19,772**
Acquisitions	110	99	**209**	**4,389**
Dispositions	(46)	–	**(46)**	**(392)**
Economic factors	(9)	(6)	**(15)**	**1,200**
2003 production	(2,032)	(6)	**(2,038)**	**(32,539)**
December 31, 2003	15,437	6,615	**22,052**	**255,791**
Change over prior year	(5,672)	2,314	**(3,358)**	**(19,230)**

1 Net present value of future net revenue of proved plus probable reserves, using forecast prices and costs, before tax, including ARC, discounted at 10%. Based on the January 2004 escalated oil and gas price forecasts by an independent qualified reserves evaluator.

The application of NI 51-101 resulted in downward revisions in estimates of approximately 2.4 million boe. Approximately 60% (1.4 million boe) of the revisions relate to the new 50-year truncation of the producing life of reserves. This affected reserves primarily in mature areas of western Alberta, where production and decline rates are low, resulting in long reserve lives. The financial impact of the 50-year cut-off is insignificant, since the present value of these reserves is small. Other technical revisions (1.0 million boe) were primarily due to a more conservative approach in estimating and, to a lesser extent, to changes in reservoir performance.

These changes also resulted in a decline in our reserve life index (RLI) to 11.0 years versus 12.2 years as reported for 2002 (using gross established reserves and 2002 gross production). For comparison purposes, our RLI for 2002 under NI 51-101 would have been 11.9 years.

RLI is a simplified representation of the number of years of reserves remaining if production remained constant at current rates. The actual productive life of the reserves is significantly longer due to a declining production rate over time.

Reserve Life Index (RLI)[1]	Proved Producing	Total Proved	Proved Plus Probable
Net reserves (mboe)[2]	15,120	15,437	22,052
Production (mboe)[3]	1,829	1,860	1,998
RLI (years)	8.3	8.3	11.0

1 Calculated by dividing the evaluators' forecast of 2004 net interest production into the remaining net interest reserves (excludes potash reserves).
2 Net reserves include the principal products (light and medium crude oil, heavy oil and natural gas) and associated gas and natural gas liquids.
3 Production includes the principal products (light and medium crude oil, heavy oil and natural gas) and associated gas and natural gas liquids.

The following table calculates the reserve life index separately for light and medium oil, heavy oil and natural gas. The production and reserves used in the calculations are based on the evaluator's forecasts of 2004 net interest production divided into the remaining net interest reserves. These estimates do not include associated gas and natural gas liquids production or reserves and therefore will not equal the RLI for the Trust calculated on a boe basis as provided in the table above.

RLI By Principal Product[1]	Proved Producing	Total Proved	Proved Plus Probable
Light and medium oil			
Net reserves (mbbls)	4,694	4,706	6,203
Production (mbbls)	438	438	470
RLI (years)	10.7	10.7	13.2
Heavy oil			
Net reserves (mbbls)	4,848	5,114	8,106
Production (mbbls)	771	796	857
RLI (years)	6.3	6.4	9.4
Natural gas			
Net reserves (mmcf)	22,109	22,325	31,371
Production (mmcf)	2,625	2,660	2,865
RLI (years)	8.4	8.4	11.0

1 Based on principal product type within production group and excludes associated gas and natural gas liquids.

Development and Acquisition Costs[1]	Three-year Results	2003	2002	2001
Development costs				
Development expenditures ($000s)	11,832	**5,894**	2,946	2,992
Change in future development capital estimates ($000s)	5,849	**3,429**	2,116	304
	17,681	**9,323**	5,062	3,296
Net reserve additions by development (mboe)	3,235	**911**	965	1,359
Development cost ($/boe)	5.47	**10.23**	5.25	2.43
Acquisition costs				
Acquisition expenditures ($000s)	35,419	**3,386**	2,326	29,707
Net reserve additions by acquisition (mboe)	2,978	**209**	234	2,535
Acquisition cost ($/boe)	11.89	**16.20**	9.94	11.72
Total development and acquisition costs				
Total expenditures ($000s)	47,251	**9,280**	5,272	32,699
Change in future development capital estimates ($000s)	5,849	**3,429**	2,116	304
	53,100	**12,709**	7,388	33,003
Net reserve additions (mboe)	6,213	**1,120**	1,199	3,894
Development and acquisition cost ($/boe)	**8.55**	**11.35**	**6.16**	**8.48**

1 Development costs equal development expenditures plus change in future capital, divided by reserves added. The 2003 reserves data is not directly comparable to historical data due to new reserve definitions and evaluation methodology that came into effect in 2003. Reserves for 2003 were evaluated under National Instrument 51-101 and are reported as net proved plus probable reserves. Previously, reserves were evaluated under National Policy 2-B and reported as gross proved plus half probable (established) reserves.

NET ASSET VALUE

Net asset value is an estimate of the underlying value of our reserves and undeveloped land, prior to provision for income taxes, interest expense, general and administrative costs and management fees, but taking into consideration estimated royalties, operating costs, other income, capital costs and abandonment costs. Future net revenue estimates are greatly influenced by price forecasts and future reservoir performance.

Using proved plus probable net interest reserves, net asset value before tax as of December 31, 2003 (discounted at 10%) was $8.08 per Trust Unit, compared with $8.74 at year-end 2002. Year over year, the major variances in the composition of asset value were an increase in the number of Trust Units outstanding, a reduction in bank debt, and the value of oil and gas reserves discussed above.

Net Asset Value, as at December 31, 2003		Discounted at	
($000s, except unit data)	10%	12%	15%
Present value of proved plus probable oil and gas reserves[1]	**255,791**	232,240	204,999
Present value of potash reserves[2]	**5,551**	4,832	4,068
Undeveloped land[3]	**5,129**	5,129	5,129
Reclamation fund	**1,289**	1,289	1,289
Working capital	**4,413**	4,413	4,413
Bank debt	**(18,000)**	(18,000)	(18,000)
Net asset value	**254,173**	229,903	201,898
Trust Units outstanding	**31,454,236**	31,454,236	31,454,236
Net asset value per Trust Unit ($)	**8.08**	**7.31**	**6.42**

1 Evaluated by Trimble and includes ARC.
2 Evaluated by Rife Resources Ltd.
3 Evaluated by Seaton-Jordan & Associates Ltd.

▸ management's report

Management has prepared the accompanying combined financial statements of Freehold Royalty Trust in accordance with Canadian generally accepted accounting principles.

Management is responsible for the accuracy and integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded, transactions are properly authorized and reliable accounting records are produced for financial reporting purposes.

External auditors, KPMG LLP, were appointed by the Trust's Unitholders to perform an examination of the corporate and accounting records so as to express an opinion on the combined financial statements of Freehold Royalty Trust. Their examination included a review and evaluation of Freehold's internal control systems and included tests and procedures considered necessary to provide reasonable assurance that the combined financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The board of directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. It exercises its responsibilities primarily through the audit committee, all of whose members are independent directors of Freehold Resources Ltd. The committee meets with management and the independent auditors to ensure that management's responsibilities are properly discharged.

D J Sandmeyer

David J. Sandmeyer
President & Chief Executive Officer
February 19, 2004

J.N. Holowisky

Joseph N. Holowisky
Vice-President, Finance & Administration,
Chief Financial Officer and Secretary

▸ auditors' report

TO THE UNITHOLDERS OF FREEHOLD ROYALTY TRUST

We have audited the combined balance sheets of Freehold Royalty Trust as at December 31, 2003 and 2002, and the combined statements of income, Unitholders' equity and cash flows for the years ended December 31, 2003 and 2002. These combined financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these combined financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these combined financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2003 and 2002, and the results of its operations and its cash flows for the years ended December 31, 2003 and 2002, in accordance with Canadian generally accepted accounting principles.

KPMG LLP

KPMG LLP
Chartered Accountants
Calgary, Canada
February 19, 2004

combined balance sheets

($000s)	December 31 2003	2002
Assets		
Current assets:		
Cash	$ 57	$ 316
Accounts receivable	11,629	13,443
	11,686	13,759
Reclamation fund (note 6)	1,289	1,006
Petroleum and natural gas interests, net of accumulated depletion and depreciation of $154,070 (2002 – $132,399)	197,165	209,557
	$ 210,140	$ 224,322
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	$ 3,145	$ 3,020
Accounts payable and accrued liabilities	4,174	2,819
	7,319	5,839
Provision for future site restoration (note 6)	1,773	1,353
Long-term debt (note 2)	18,000	30,000
Future income tax liability (note 8)	1,955	1,650
Unitholders' equity (note 3)	181,093	185,480
	$ 210,140	$ 224,322

See accompanying notes to combined financial statements.

Approved on behalf of Freehold Royalty Trust by Freehold Resources Ltd., as Administrator:

William W. Siebens
Director

D. Nolan Blades
Director

▸ combined statements of income

($000s, except per unit data)	Years Ended December 31 2003	2002
Revenue:		
Royalty income and working interest sales	$ 73,166	$ 63,143
Royalty expense (net of ARC)	(3,197)	(2,709)
	69,969	60,434
Expenses:		
Operating	5,190	4,679
General and administrative	2,866	2,823
Interest on long-term debt	778	1,060
Depletion and depreciation	21,671	21,083
Provision for future site restoration	455	346
Management fee (note 5)	1,235	971
	32,195	30,962
Net income before taxes	37,774	29,472
Income and capital taxes (note 8)	443	265
Future income tax provision (note 8)	305	1,650
Net income	$ 37,026	$ 27,557
Net income per Trust Unit, basic and diluted	$ 1.19	$ 0.91

See accompanying notes to combined financial statements.

▸ combined statements of unitholders' equity

($000s)	December 31 2003	2002
Unitholders' equity, beginning of year	$ 185,480	$ 196,442
Net income	37,026	27,557
Distributions to Unitholders (note 7)	(53,149)	(39,530)
Issue of new Trust Units	11,736	1,011
Unitholders' equity, end of year	$ 181,093	$ 185,480

See accompanying notes to combined financial statements.

combined statements of cash flows

($000s)	Years Ended December 31 2003	2002
Cash provided by (used in):		
Operating:		
Net income	$ 37,026	$ 27,557
Items not involving cash:		
Depletion and depreciation	21,671	21,083
Future income tax provision	305	1,650
Provision for future site restoration	455	346
Trust Units issued in lieu of management fee	1,235	971
Funds generated from operations	60,692	51,607
Changes in non-cash working capital (note 9)	3,169	(3,555)
	63,861	48,052
Financing		
Trust Units issued upon exercise of options	10,501	40
Long-term debt	(12,000)	(3,000)
Distributions paid	(53,024)	(39,524)
	(54,523)	(42,484)
Investing:		
Property and royalty acquisitions (note 5)	(3,386)	(2,326)
Development expenditures	(5,894)	(2,946)
Site reclamation fund contributions	(317)	(240)
	(9,597)	(5,512)
Increase (decrease) in cash	(259)	56
Cash, beginning of year	316	260
Cash, end of year	$ 57	$ 316

Cash interest paid during 2003 was $712 (2002 – $1,071).
See accompanying notes to combined financial statements.

▸ notes to combined financial statements

Years ended December 31, 2003 and 2002.

BASIS OF PRESENTATION

Freehold Royalty Trust ("the Trust") is an open-end investment trust formed under the laws of the Province of Alberta pursuant to a Trust Indenture dated September 30, 1996, as amended from time to time. The Trust holds royalty interests directly and a 99% royalty interest in the funds generated by Freehold Resources Ltd. ("Resources").

Resources was incorporated on June 3, 1996, and derives its income from certain oil and gas working interest properties.

These combined financial statements include the accounts of the Trust and Resources. All inter-entity transactions have been eliminated.

1. SIGNIFICANT ACCOUNTING POLICIES

(a) Property, plant and equipment:
The Trust follows the full cost method of accounting.

All costs of acquiring, exploring for and developing oil and gas and related reserves are capitalized. Such costs include land acquisition, geological and geophysical, carrying charges of unproved properties, costs of drilling both productive and non-productive wells and directly related general and administrative costs. Costs are reduced by proceeds from the sale of oil and gas properties and by government grants. Gains and losses are not recognized upon disposition of oil and gas properties unless such a disposition would alter the rate of depletion by 20% or more.

(b) Ceiling test:
The Trust applies a ceiling test to the carrying value of oil and gas assets, net of the provision for site restoration, plus future development costs to ensure that such costs do not exceed future estimated net revenues from production of proved reserves at year-end prices and costs. Future revenues are calculated after deducting future general and administrative costs, financing costs, site restoration costs and Resources' income taxes.

(c) Depletion:
Oil and gas properties and royalty interests, including the costs of production equipment and future capital costs associated with proved reserves, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. Reserves are converted to equivalent units on the basis of relative energy content.

(d) Provision for future site restoration:
Estimated future site restoration costs are provided for using the unit-of-production method. Costs are estimated by the Trust based on current regulations, costs, technology and industry standards. Actual site restoration costs are charged to the accumulated provision account as incurred.

(e) Income and other taxes:
The Trust is a taxable trust under the *Income Tax Act* (Canada) and it distributes substantially all of its taxable income to its Unitholders. The tax deductions received by the Trust for the distributions to Unitholders represent an exemption from taxation equivalent to the Trust's earnings. In addition, the Trust is exempt from future income taxes because it is contractually committed to distribute all of its income to its Unitholders.

Resources follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. Resources can deduct royalty payments to the Trust in determining taxable income and is generally liable for income taxes on its 1% residual interest.

(f) Cash:
Cash includes cash on deposit and highly liquid investments with original maturities of three months or less.

(g) Measurement uncertainty:
The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses during the reporting period. Actual results could differ as a result of using estimates.

(h) Stock based compensation plans:
In accordance with the Trust's Unit Option Plan, Trust Units are granted to the independent directors of Resources and to the Manager, Rife Resources Management Ltd. The Trust does not recognize compensation expense on the issuance of Trust Unit options under this plan, as the exercise price of the Trust Unit options is equal to the market value of Trust Units on the day they are granted.

Effective January 1, 2002, new accounting standards were adopted for stock-based compensation and other stock-based payments. The new standards require additional disclosure for options granted to employees, officers and directors and that a compensation cost be recorded for the fair value of options granted to non-employees. There was no significant impact on the financial statements upon adoption of this standard, however grants of options to the Manager and any other non-employees subsequent to January 1, 2002, will result in a compensation cost charged to income.

(i) Earnings per unit:
Basic units outstanding are the weighted average number of units outstanding for each period. Diluted units outstanding are calculated using the treasury stock method, which assumes that any proceeds received from in-the-money options would be used to buy back units at the average market price for the period.

2. LONG-TERM DEBT

The Trust has a $50.0 million committed production facility on which $18.0 million was drawn at December 31, 2003 (2002 – $30.0 million). The facility is secured by a General Security Agreement from the Trust and Resources providing a first priority security interest in both Resources' and the Trust's assets and specific assignment of royalties. A demand debenture is pledged from both Resources and the Trust in the amount of $100.0 million, conveying a first floating charge over all property. The facility is structured as a one year committed revolving credit facility, extendible annually. In the event that the lender does not consent to such extension, the revolving credit facility will convert to a three year non-revolving amortizing term loan with principal payments due quarterly. At December 31, 2003 and 2002, the entire amount outstanding under the production facility is presented as long-term based on the Trust's ability to refinance any current amount with the undrawn portion of the facility.

In addition, the Trust has available a $15.0 million demand operating facility and a U.S. $10.0 million swap facility, of which nil was drawn down as at December 31, 2003 and 2002. The facilities have security similar to that of the production facility with any amounts outstanding payable on demand.

Borrowings under the facility bear interest at the Bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 90 to 165 basis points.

3. UNITHOLDERS' EQUITY

The Trust has authorized an unlimited number of Trust Units of which 31,454,236 (2002 – 30,225,236) were issued at December 31, 2003.

Trust Units Issued	2003 Number	2003 Amount ($000s)	2002 Number	2002 Amount ($000s)
Balance, beginning of year	30,225,236	$ 285,772	30,129,236	$ 284,761
Issued upon exercise of options	1,139,000	10,501	6,000	40
Issued in lieu of management fee	90,000	1,235	90,000	971
Balance, end of year	31,454,236	$ 297,508	30,225,236	$ 285,772

The Trust has reserved 820,000 Trust Units pursuant to a Trust Unit Option Plan. Options to purchase Trust Units may be issued to the independent directors of Resources or the Manager.

As at December 31, 2003, no options to purchase Trust Units were outstanding (2002 – 1,139,000 outstanding and vested). During 2003, 1,139,000 options were exercised (9,000 at $6.65 and 1,130,000 at $9.24).

The Trust has reserved 500,000 Trust Units pursuant to its management agreement with the Manager, of which 174,236 have been issued to date (see note 5).

The weighted average number of Trust Units outstanding for 2003 was 31,164,161 (2002 – 30,165,167).

4. DISTRIBUTIONS

Distributable income is paid on a monthly basis, with payments to be made on the fifteenth day following the month-end.

5. RELATED PARTY TRANSACTIONS

The Manager provides certain services for a fee based on a specified number of Trust Units per quarter, pursuant to a management agreement which has a term of three years and is subject to renewal on November 26, 2004. During 2003, the management fee charged was 90,000 Trust Units with an ascribed value of $1,235,000 (2002 – 90,000 Trust Units with an ascribed value of $971,000).

During the year, the Manager charged the Trust $2,274,000 (2002 – $2,035,000) in general and administrative costs. At December 31, 2003, there was $343,000 (2002 – $148,000) included in accounts payable relating to these costs.

The Manager also earns a fee of 1.5% of the purchase price of oil and gas properties acquired by Freehold. During 2003, the Manager acquired $3,512,000 ($3,386,000 net) of properties on behalf of the Trust (2002 – $2,532,000, net $2,326,000) and was paid $52,000 (2002 – $38,000) relating to these acquisitions. This fee is charged to capital assets as part of the properties acquired.

6. FUTURE SITE RESTORATION AND RECLAMATION COST

The Trust and Resources are liable for their share of ongoing environmental obligations and for the ultimate reclamation of the working interest properties upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow. The total estimated future environmental and reclamation obligations in respect of the working interest properties are approximately $7.0 million (2002 – $5.6 million). A reclamation fund, consisting of cash invested in an interest-bearing account, has been established and is funded by quarterly cash payments. During the period, $34,000 (2002 – $118,000) in site restoration was incurred and paid from the reclamation fund.

The costs of unproved lands at December 31, 2003, of $3.0 million, have been excluded from the depletion calculation.

7. DISTRIBUTABLE INCOME

($000s, except per unit data)	Years Ended December 31 2003	2002
Funds generated from operations	$ 60,692	$ 51,607
Site reclamation fund contributions	(317)	(240)
Capital expenditures[1]	(5,894)	(2,946)
Debt repayment from cash flow	(1,499)	(3,000)
Property and royalty acquisitions	(3,386)	(2,326)
Working capital change	3,553	(3,565)
Distributable income	$ 53,149	$ 39,530
Per Trust Unit	$ 1.70	$ 1.31

1 The amount of capital expenditures is limited to 15% of annual net cash flow from operations, unless additional capital expenditures are financed with borrowings, additional issuances of Trust Units or proceeds from the disposition of assets.

8. INCOME TAXES

Resources uses the liability method of accounting for income taxes, as described in note 1. The provision for income taxes in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial tax rate to the Trust's earnings before income taxes. This difference results from the following items:

($000s)	2003	2002
Earnings before income taxes and capital taxes	$ 37,774	$ 29,472
Combined federal and provincial tax rate	41.0%	42.6%
Computed "expected" income tax expense	$ 15,478	$ 12,537
Increase (decrease) in income tax resulting from:		
Non-taxable earnings of the Trust	(13,881)	(10,031)
Non-deductible Crown charges	10	9
Resource allowance	(417)	(547)
Benefit of future federal rate reductions	(358)	–
Changes in enacted tax rates	(54)	–
Benefit of provincial royalty tax deductions	(139)	–
Other	6	(3)
	$ 645	$ 1,965
Change in valuation allowance	–	(193)
Total income taxes	$ 645	$ 1,772
Total income taxes are comprised of:		
Current taxes	$ 340	$ 122
Future taxes	305	1,650
Total income taxes	$ 645	$ 1,772
Capital taxes	$ 103	$ 143

In 2003, Resources made cash payments of $440,000 in taxes (2002 – $150,000).

The components of Resources' future income taxes at December 31 are as follows:

($000s)	2003	2002
Future income tax liabilities:		
Oil and natural gas properties	$ 2,567	$ 2,080
Future income tax assets:		
Abandonment costs	(612)	(430)
Future income taxes	$ 1,955	$ 1,650

9. SUPPLEMENTAL CASH FLOW DISCLOSURE

($000s)	2003	2002
Changes in non-cash working capital balance		
Accounts receivable	$ 1,814	$ (4,369)
Accounts payable and accrued liabilities	1,355	814
	$ 3,169	$ (3,555)

five-year review

Financial ($000s, except unit data)	**2003**	2002	2001	2000	1999
Gross revenue	**73,166**	63,143	61,885	64,500	36,355
Expenses					
Operating expenses	**5,190**	4,679	4,415	4,080	3,555
General and administrative expenses	**2,866**	2,823	2,244	2,097	1,882
Interest expense	**778**	1,060	1,814	2,700	2,410
Depletion and depreciation	**21,671**	21,083	21,402	19,257	17,926
Capital expenditures	**5,894**	2,946	2,992	5,161	940
Property acquisitions	**3,386**	2,326	29,707	5,326	–
Distributable income	**53,149**	39,530	45,264	35,226	20,757
per Trust Unit ($)	**1.70**	1.31	1.56	1.32	0.78
Total assets	**210,140**	224,322	235,585	227,356	232,312
Long-term debt	**18,000**	30,000	33,000	38,000	39,288
Unitholders' equity	**181,093**	185,480	196,442	183,029	185,938
Trust Units outstanding					
End of year	**31,454,236**	30,225,236	30,129,236	26,728,000	26,648,000
Weighted average	**31,164,161**	30,165,167	28,839,216	26,678,328	26,598,411
Operating					
Production					
Oil and NGLs (bbls/d)	**4,005**	4,214	4,227	3,680	3,223
Natural gas (mmcf/d)	**10.9**	10.7	11.2	11.0	11.2
Oil equivalent (boe/d)	**5,817**	6,004	6,086	5,523	5,082
Potash (tonnes/d)	**7.6**	7.8	7.9	10.9	14.2
Average sales price					
Oil and NGLs ($/bbl)	**32.63**	30.83	24.88	32.97	21.37
Natural gas ($/mcf)	**6.18**	3.81	5.64	4.71	2.48
Oil equivalent ($/boe)	**34.01**	28.44	27.63	31.39	18.99
Potash ($/tonne)	**133.36**	143.33	153.98	146.72	157.56
Undeveloped land (gross acres)	**242,205**	235,062	237,443	140,896	136,036
Reserves (mboe)[1]	**22,052**	26,813	28,177	28,150	29,062
Trading Activity					
High ($)	**17.19**	11.35	10.10	9.50	6.90
Low ($)	**10.50**	9.00	8.00	5.60	4.13
Close ($)	**16.35**	10.88	9.20	8.70	5.95
Volume (000s)	**10,970**	7,323	8,162	6,752	5,782

1 The 2003 reserves data is not directly comparable to historical data, due to new reserve definitions and evaluation methodology that came into effect in 2003. Reserves as at December 31, 2003, were independently evaluated under NI 51-101 and are reported as net proved plus probable reserves. Previously, reserves were evaluated under National Policy 2-B and are reported as gross proved plus half probable (established) reserves (see pages 32-36).

▸ unitholder tax information

FOR CANADIAN TAXPAYERS

For purposes of the *Income Tax Act* (Canada), Freehold is treated as a mutual fund trust. Each year, Freehold files a T3 income tax return with the taxable income allocated to and made taxable in the hands of Unitholders. This taxable income is allocated, on T3 supplementary forms, to each Unitholder who received distributions in that taxation year. The T3 slip will report only the other income component in Box 26. This income is taxed as ordinary income. The portion deemed return of capital reduces the Unitholder's adjusted cost base in the Trust Units and should be included in the computation of capital gain (or loss) at the time of disposition.

2003 TAX INFORMATION

Record Date	Payment Date	Taxable Amount Box 26 (Other Income) ($/Trust Unit)	Tax-Deferred Amount (Return of Capital) ($/Trust Unit)	Total Cash Distribution Paid ($/Trust Unit)
December 31, 2002	January 15, 2003	$ 0.0690	$ 0.0310	$ 0.10
January 31, 2003	February 15, 2003	0.0690	0.0310	0.10
February 28, 2003	March 15, 2003	0.1380	0.0620	0.20[1]
March 31, 2003	April 15, 2003	0.0690	0.0310	0.10
April 30, 2003	May 15, 2003	0.0690	0.0310	0.10
May 31, 2003	June 15, 2003	0.2070	0.0930	0.30[1]
June 30, 2003	July 15, 2003	0.0690	0.0310	0.10
July 31, 2003	August 15, 2003	0.0690	0.0310	0.10
August 31, 2003	September 15, 2003	0.1380	0.0620	0.20[1]
September 30, 2003	October 15, 2003	0.0690	0.0310	0.10
October 31, 2003	November 15, 2003	0.0690	0.0310	0.10
November 30, 2003	December 15, 2003	0.1380	0.0620	0.20[1]
Total paid during the 2003 taxation year		$ 1.1730	$ 0.5270	$ 1.70

1 Regular monthly distributions are supplemented by quarterly top-ups when excess funds are available. Payment includes quarterly top-up.

ADJUSTED COST BASE CALCULATION FOR CAPITAL GAINS PURPOSES

Unitholders are required to reduce the adjusted cost base (ACB) of their Trust Units by the amount equal to any distributions received in the form of return of capital (the tax-deferred portion of distributions received). Unitholders should maintain a record of all distributions that are classified as partially or entirely a return of capital distribution while holding Freehold Trust Units. For Freehold investors in the $10.00 per Trust Unit initial public offering in November 1996, the ACB of Trust Units still held as at December 31, 2003 is $4.0756 per Trust Unit, taking into account the cumulative return of capital of $5.9244.

HISTORICAL TAX INFORMATION

Payment Period[1]	Taxable Amount[2] (Other Income) ($/Trust Unit)	Tax Deferred Amount[3] (Return of Capital) ($/Trust Unit)	Amount Taxable (%)	Amount Tax Deferred ($/Trust Unit)	Total Cash Distribution for Tax Purposes ($/Trust Unit)
2003	**$ 1.1730**	**$ 0.5270**	**69%**	**31%**	**$ 1.70**
2002	0.7598	0.5502	58%	42%	1.31
2001	0.5928	0.9672	38%	62%	1.56
2000	0.0000	1.2900	0%	100%	1.29
1999	0.0000	0.7600	0%	100%	0.76
1998	0.0000	0.8500	0%	100%	0.85
1997	0.0000	0.9800	0%	100%	0.98

1 For income tax purposes, only cash payments received in each calendar year are subject to Canadian income tax.
2 As at December 31, 2003, the Trust has the benefit of $167 million of income tax accounts to reduce the taxable portion of future distributions.
3 The tax-deferred amount reduces the adjusted cost base of a Unitholder's investment in the Trust. A more detailed list of historical distributions (showing record dates, payment dates and tax treatment) can be obtained from Freehold's Website, www.freeholdtrust.com, or by contacting Freehold directly.

FOR FOREIGN TAXPAYERS

The following information is provided for general information only. Unitholders who are not residents of Canada for income tax purposes are encouraged to seek advice from a qualified tax advisor in their country of residence for the tax treatment of distributions.

NON-RESIDENT WITHHOLDING TAX

Monthly income distributions payable to non-residents of Canada are normally subject to a withholding tax of 25% as prescribed by the *Income Tax Act* (Canada). This withholding tax may be reduced in accordance with reciprocal tax treaties.

TAX CONSIDERATIONS FOR U.S. RESIDENTS

In the case of the Tax Treaty between Canada and the U.S., the withholding tax for U.S. residents is prescribed at 15%. U.S. taxpayers may be eligible for a foreign tax credit with respect to the Canadian withholding taxes paid. U.S. investors may also seek a refund of Canadian withholding tax related to amounts withheld on non-taxable distributions (from a Canadian tax perspective) from Canada Revenue Agency by filing Form NR7-R, Application for Refund of Non-Resident Tax Withheld.

Freehold has not made an election to be treated as a Partnership and is therefore deemed to be a Corporation for U.S. tax purposes.

U.S. tax rules state that no portion of the distribution will be considered a tax-deferred return of capital unless the trust computes its current and accumulated earnings and profits in accordance with U.S. income tax principles. Because a current and accumulated earnings and profits calculation is not performed by Freehold at this time, distributions are 100% taxable to U.S. residents as a dividend. However, such dividends may be eligible for the lower U.S. tax rate allowed on dividends from certain foreign corporations. Please consult your U.S. tax advisor.

2003 DISTRIBUTIONS IN U.S. DOLLARS

Record Date	Payment Date	Total Distributions Paid in Cdn.$ ($/Trust Unit)	U.S. Exchange Rate (U.S.$)	Total Distribution Paid in U.S.$ ($/Trust Unit)
December 31, 2002	January 15, 2003	$ 0.10	1.5796	$ 0.063307
January 31, 2003	February 15, 2003	0.10	1.5215	0.065725
February 28, 2003	March 15, 2003	0.20[1]	1.4871	0.134490
March 31, 2003	April 15, 2003	0.10	1.4693	0.068060
April 30, 2003	May 15, 2003	0.10	1.4335	0.069759
May 31, 2003	June 15, 2003	0.30[1]	1.3708	0.218850
June 30, 2003	July 15, 2003	0.10	1.3553	0.073784
July 31, 2003	August 15, 2003	0.10	1.4073	0.071058
August 31, 2003	September 15, 2003	0.20[1]	1.3851	0.144394
September 30, 2003	October 15, 2003	0.10	1.3504	0.074052
October 31, 2003	November 15, 2003	0.10	1.3197	0.075775
November 30, 2003	December 15, 2003	0.20[1]	1.2973	0.154166
Total paid during the 2003 taxation year		**$ 1.70**		**$ 1.213421**

1 Regular monthly distributions are supplemented by quarterly top-ups when excess funds are available. Payment includes quarterly top-up.

▸ unitholder information

SHARE CAPITAL

The Trust is authorized to issue an unlimited number of Trust Units. As at December 31, 2003, there were 31,454,236 Trust Units outstanding.

	2003				2002			
Trading Activity	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
High ($)	11.85	13.48	13.85	17.19	10.35	10.95	11.35	11.33
Low ($)	10.50	11.20	12.81	13.11	9.00	9.58	9.50	10.00
Close ($)	11.78	13.05	13.70	16.35	10.25	10.85	11.17	10.88
Volume (000s)	3,025	2,447	2,991	2,506	1,829	1,572	2,428	1,494

DISTRIBUTION POLICY AND DATES

The Trust makes monthly distributions, the amounts of which are determined by the board of directors, and subject to change depending upon the business environment. Record dates are the end of each month, and payment dates are the fifteenth day of the following month. Regular monthly distributions are supplemented by quarterly top-ups when excess funds are available.

UNITHOLDER PLANS

Direct Deposit Plan: A Direct Deposit Plan is in place to provide Unitholders who have Canadian bank accounts with a method of receiving cash distributions as a direct deposit into their bank account.

Distribution Reinvestment Plan (DRIP): A DRIP is in place to provide Unitholders who are residents of Canada with a method of reinvesting cash distributions into new Trust Units.

U.S. Currency Payment Plan: Unitholders may elect to receive their distribution payments in U.S. funds.

TRANSFER AGENT

For information about distribution cheques, Trust Unit certificates, stock transfers, duplicate mailings and address changes, please contact:

Computershare Trust Company of Canada
600, 530 – 8 Avenue S.W.
Calgary, Alberta T2P 3S8
Telephone: (403) 267-6555
Fax: (403) 267-6598
Toll Free: 1-888-267-6555
Email: service@computershare.com

ANNUAL MEETING NOTICE

The Annual and Special Meeting of Unitholders will be held on Wednesday, May 5, 2004, at 3:30 p.m. in the Lecture Theatre, Sunlife Plaza Conference Centre, Plus 15 (2nd level), 140 – 4 Avenue S.W., Calgary, Alberta.

corporate information

BOARD OF DIRECTORS

William W. Siebens[2]
D. Nolan Blades[1, 2, 3]
Harry S. Campbell, Q.C.[3]
Tullio Cedraschi
Peter T. Harrison[1, 3]
Dr. P. Michael Maher[1, 2]
David J. Sandmeyer

1 Audit Committee
2 Governance & Nominating Committee
3 Reserves Committee

OFFICERS

William W. Siebens
Chairman

David J. Sandmeyer
President & Chief Executive Officer

J. Frank George
Vice-President, Exploitation

Darren G. Gunderson
Controller

Joseph N. Holowisky
Vice-President, Finance & Administration,
Chief Financial Officer and Secretary

William O. Ingram
Vice-President, Production

Michael J. Okrusko
Vice-President, Land

HEAD OFFICE

Freehold Resources Ltd.
Freehold Royalty Trust
400, 144 – 4 Avenue S.W.
Calgary, Alberta T2P 3N4
Telephone: (403) 221-0802
Fax: (403) 221-0888
Website: www.freeholdtrust.com

STOCK EXCHANGE LISTING

Toronto Stock Exchange (www.tsx.com)
Symbol: FRU.UN

TRUSTEE AND TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta and Toronto, Ontario

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

AUDITORS

KPMG LLP
Calgary, Alberta

BANKER

Canadian Imperial Bank of Commerce
Calgary, Alberta

EVALUATION ENGINEERS

Trimble Engineering Associates Ltd.
Calgary, Alberta

INVESTOR RELATIONS CONTACT

Karen C. Taylor
Manager, Investor Relations

Phone: (403) 221-0891
Toll Free: 1-888-257-1873
Email: ir@freeholdtrust.com

Please visit our website: **www.freeholdtrust.com** for annual and quarterly reports, fact sheet, news releases, corporate presentations, trading activity and information on cash distributions and Unitholder taxation.

Freehold
ROYALTY TRUST

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Telephone: (403) 221-0802 Fax: (403) 221-0888
Website: www.freeholdtrust.com